Planning for the Indian Power Sector:
Environmental and Development Considerations

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CANADIAN ENERGY RESEARCH INSTITUTE

The Canadian Energy Research Institute (CERI) is a cooperative research organization established by government and industry parties in 1975. The Institute's principal role is to undertake objective, independent studies to assist corporations and governments in making energy and energy-related decisions and policy choices. Related important objectives are the ongoing government/industry review of energy issues and policies and the development of expertise in the analysis of energy matters.

The sponsors of the Institute are Natural Resources Canada (formerly Energy, Mines and Resources Canada); the Alberta Department of Energy; the Private Energy Research Association (composed of more than one hundred and thirty corporate members from the energy production, transportation, marketing, distributing and consuming industries in Canada and abroad and from the financial community); the University of Calgary; the Ontario Ministry of Environment and Energy; the Saskatchewan Department of Energy and Mines; the Energy Resources Conservation Board (Alberta); the British Columbia Ministry of Energy, Mines and Petroleum Resources; the Northwest Territories Department of Energy, Mines and Petroleum Resources; and Indian and Northern Affairs Canada. In addition, the Institute is supported by grants from international associate sponsors (mainly foreign-based energy companies and research organizations) which benefit from CERI research pertaining to oil, natural gas, coal and electricity economics.

CERI's research program is determined by a Board of Directors named by the sponsoring organizations. Project advisory committees comprised of experts from government and industry are established to assist Institute staff and to review preliminary drafts of CERI reports. Responsibility for the content of studies rests with the author(s) and the officers of the Institute. All studies are placed in the public domain.

TATA ENERGY RESEARCH INSTITUTE

Energy is a primary input in the production of goods and services. Historically, the role of energy in contributing towards human welfare has increased in significance along with industrialization and the organized development of the services sector as it exists in modern society. From its early role, which was confined to the kitchen as the fuel for household cooking, energy is now a major input in sectors such as industry, commerce, transport, and telecommunications, besides the wide range of services required in the household sector. As a result of the far-reaching changes in the forms of energy and their respective shares in supporting human activities, research and training on various aspects of energy have assumed growing importance. Analysis of interactions between energy, environment, and the evolution of scientific knowledge related to these fields lend great importance to the complex system which pervades even the air we breath for our survival. The present pattern of economic growth is known to degade environmental quality and deplete natural resources unsustainable. This requires solutions that promote the concept of sustainable development.

TERI (Tata Energy Research Institute) was set up essentially to tackle the immense and acute problems that mankind is likely to face in the years ahead on account of (i) the gradual depletion of the earth's finite energy resources which are largely non-renewable; and (ii) the existing methods of their use, which lead to increasing pollution.

The mission of TERI, therefore, is to find solutions to a range of problems, and it is this characteristic which imparts a definite goal-orientation to all the activities undertaken within the Institute.

TERI's programmes reflect its wide-ranging charter and illustrate its integrated and multi-disciplinary approach. The Institute is currently active on eight broad fronts, namely (1) Policy analysis on energy and environment, (2) Rural energy, (3) Forestry, (4) Renewable energy technologies, (5) Energy conservation , (6) Bio-technology, (7) Computer applications, and (8) Training and information dissemination.

Programmes in each of these eight areas attach problems at several levels and scales. For instance, studies on smoke pollution in rural kitchens and studies in cell and protoplast cultures represent TERI's range at the micro-level. The development of mathematical models to depict and simulate the entire country's energy-economy system in 2010 and beyond is an example of research at the macro-level. Training programmes are another example: they range from those aimed at the owners of improved chulhas and biogas plants to those that involve policy makers and senior civil servants. Geographically too, TERI's brief is wide: it has been fortunate to receive the support of the central and state governments and of many international organizations including the

World Bank, the Asian Development Bank, Ford Foundation, the International Development Research Centre, the Commission of the European Communities, the UN University, ESCAP, UNESCO, FAO, and others. To complement its research and training activities, the Institute is active in publishing several forms of literature on energy and the environment, ranging from abstracting services to in-depth state-of-the-art reports on various topics.

TERI was set up in 1974 with generous funding from some Tata companies spearheaded by Tata Chemicals. As TERI's stature and credibility have grown nationally and internationally, it continues to attract projects and support from a wide range of organizations as it does talent to the ranks of its staff from the best institutions spread over the globe.

TERI is a young institute, growing rapidly, By mid-1994, it had on its staff more than 200 professionals whose average age reflects the vigour, enthusiasm, and idealism of youth, perhaps more so than any other institute in this country. The professional vitality of its staff, a consciously built, stimulating work-culture, a sense of self-imposed discipline that blends the best of inspired management, and a well-regulated and smoothly run administration are TERI's major strengths-essential prerequisites for the pursuit of excellence.

TERI is now in the phase of consolidating upon its current strengths. Most of its Four Year Plan (1988-92) is now a reality; the second Four Year Plan (1992-96) is now being implemented. TERI is widening its horizons further. the Institute hosts the secretariat of the Asian Energy Institute, a network of energy institutions from nearly a dozen countries of the Asia-Pacific region. TERI is also one of the first developing country research organizations to have set up an affiliate in Washington - the Tate Energy and Resources Institute was registered in the United States in August 1990.

Poised for the 21st century, TERI is confident of meeting the high expectations of its supporters and justifying the faith they have placed in it.

Foreword

The Canadian International Development Agency (CIDA) in conjunction with the Conference Board of Canada initiated in 1992 a program to stimulate linkages between Canadian and Indian organizations and to fostei long-term business relationships. Because research institutes are seen to play an important role in bridging information gaps and, therefore, have an integral role in developing business linkages, the Conference Board of Canada partnered a number of Canadian and Indian research organizations to jointly examine key economic and social challenges facing India. The Canadian Energy Research Institute (CERI) and the Tata Energy Research Institute (TER) were partnered to undertake joint research into development prospects and challenges for India's electricity sector

Specifically, CERI and TERI were charged with the tasks of examining the critical issues in India's electric power sector and reviewing strategies for meeting India's electricity needs in the least cost and most environmentally-sensitive manner This study reports on the findings of this joint investigation.

India's electric power sector can be characterized as one caught between environmental challenges and the country's stark economic, social, and political realities. On the one hand, Indian electric utilities are being pressured to : (i) pursue generation technologies which are as environmentally benign as possible; (ii) ensure that their customers are using electricity as efficiently as possible, and (iii) retrofit existing generation capacity with equipment to either remove or reduce harmful emissions that would otherwise be emitted into the environment On the other hand, the Indian electricity sector's ability to accomplish these objectives is severely challenged by their poor financial state and that of their customers, by the mix of central and state controls guiding power sector operations and development, and by the need to develop the Indian economy.

Clearly, a myopic review and recommendations of possible North American solutions to electricity sector problems in India is inappropriate without due recognition of India's unique circumstances. That having been said, the power sector in North American has have achieved some degree of success at meeting environmental objectives of offers resolutions that merit review, albeit with a judicious eye toward Indian solutions.

In many respects, the results contained in this study should not be surprising to the reader. Population pressures, accelerating economic development, and resulting energy and electricity demand growth, are placing increasing pressures on the energy infrastructure in India. Economic and efficiency arguments for cost-based pricing of energy services and increased foreign investment in energy sector development and delivery, must be weighed

against cultural traditions, social objectives, and equity considerations. Lurking behind all of this is the realization that "business as usual" practices are environmentally unacceptable and unsustainable in the Indian context.

It is the hope of both CERI and TERI that the insights provided in this study, and the further development and application of the analytical model created for this project, will assist in guiding policy makers through the labyrinth of competing and conflicting concerns and challenges that define the electric power sector in India. We extend our appreciation to the Canadian International Development Agency for their financial support of the Canada-India Linkage Program, and to the Conference Board of Canada for their assistance in managing this project and the larger Linkage Program.

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January 1995
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Preface

It has been often noted that one of the critical elements in raising the standard of living of a country's population is the provision of affordable, reliable energy services. The situation in India is no exception. Reliable electric power, available to the most remote community at prices that even the poorest can afford, has been a strategic objective of the Indian power sector for many years. To meet this goal, the power sector has had to compete for physical and financial resources with other sectors of the economy and with other social policy objectives of the central and state governments.

The last decade has seen the ascendence of a new factor in this development struggle, that being concern over the environmental impacts of electric power development and production. Strategies to reduce greenhouse gas emissions (carbon dioxide and methane) and regional emissions of acid gases (sulphur dioxide and nitrogen oxides) have become a critical component of the power planning process. Consequently, developing a framework to examine electric power development and emission levels under alternative energy and economic assumptions for India is an important step in providing decision makers with the information they need to make decisions

This study reports on the development of a linear programming model (India ELITE) based on an earlier version of a power planning model developed in Canada, and its use in identifying least-cost electric power system development options for India for the 1991-2021 timeframe. Importantly, the study also reports on the emissions implications of the various development scenarios examined for the Indian power sector.

An integral component of this study has been the direct involvement of key stakeholders in Canada and India who reviewed and commented upon the draft Executive Summary of this study (the project Advisory Committee) The authors wish to thank the Advisory Committee members for their valuable advice, comments and constructive criticisms.

Special thanks are due to a number of CERI staff; Lynee Buist of the I.N. McKinnon Memorial Library for background information, and Megan Murphy for her excellent work on the text and graphics and numerous revisions to these over the course of completing this study.

Executive Summary

1. Project Objectives

India's power sector is caught between the pressures to add new generating capacities to match the rapidly growing demand for power to fuel its growing economic and social development, and the environmental challenges arising from large scale power generation. New generation capacity of the order of 100,000-150,000 MW is estimated to be required during the next 15 years. Coal is and will continue to be the mainstay of power generation in India. This brings into focus the issues relating to the quantity and composition of atmospheric emissions from thermal power stations, and the need to consider appropriate technologies to reduce such emissions.

Against this background, this study was conceived to examine the critical issues in India's electric power sector and to review strategies for meeting India's electricity demand in the least cost and most environmentally sound manner. The study draws upon the experience of the North American and Canadian electric utilities in meeting environmental objectives and offers resolutions that merit review, albeit with a judicious eye towards solutions for the Indian power sector.

2. Project Design and Methodology

The project analyses and evaluates various planning options available to the Indian power sector to meet electricity demand until the year 2021 Important planning options that are evaluated include:

- decentralized energy production systems;
- demand side management strategies;
- increased cogeneration in the industrial sector;
- new and more efficient thermal electric power generation technologies, and
- reduction in transmission and distribution losses.

The planning options are studied using the MARKEL - ELGEM (Electricity Generation Expansion Model) jointly developed by CERI and the Alberta Research Council (ARC). The model is a linear programming, optimizing, electricity generation supply model ELGEM has been used by CERI to evaluate the implications of greater interregional electricity trade in Canada, the economies of clean coal and competing generation technologies in meeting Canadian power capacity requirements, and the emissions implications of alternative development scenarios for Canada's electric power sector.

The important questions that have been addressed in evaluating various planning options for India include the following.

- What are the implications of various financial and resource utilization constraints on power sector development?

- How will new capacity additions required to meet forecast electricity demand in India affect the growth in emissions of particulates, CO_2, SO_2, NO_x, and nuclear waste?

- What is the extent of resources required to fully meet projected electricity demand, and what could be the extent of unrealized demand (or alternatively, the capacity shortfall) under each constrained scenario?

- What impacts could demand-side management, clean coal technologies, cogeneration and reduced transmission and distribution losses offer for meeting electricity demand in India and reducing environmental emissions?

- What are the cost implications of electricity supply under various scenarios?

- What are the cost and emissions implications of an optimistic scenario that employs all available options in meeting India's electricity requirements?

3. Options for Meeting India's Electricity Demand

This section analyses various planning options for meeting India's electricity demand. The present status of these options and their potential to meet the electricity demand in future are examined. The experience of Canada and North America with these options are examined as well.

3.1 Decentralized Electricity Generation System

Decentralized electricity generation system offer several advantages in application where flexibility in system size and location are desired. Considerable improvements in reliability, costs, and efficiencies of these technologies, together with the rising costs of large-scale electricity generation and favorable public policy, have resulted in active consideration of dispersed electricity generation options

3.1.1 Renewable Energy Projects in Canada

Canada has a rather limited record of renewable energy development and large-scale hydro continues to dominate electrical generation in Canada accounting for 57 percent of Canada's installed capacity. Significant potential remains for development of small hydro power generation. B.C. Hydro has 23.5 MW of small hydro in service and plans to add 109 MW in future. Hydro Québec has recently signed contracts for 160 MW of small power projects most of which are small hydro projects.

Biomass is the main renewable energy source, accounting for about two percent of the installed electrical capacity in Canada. The basic constraints in promotion of biomass are availability (or the lack of) of efficient technologies for biomass conversion, significant land requirements and possible ecological impacts and transportation problems. Canada's installed wind generation capacity is only 7.5 MW though there are many promising sites which have been taken up for field testing. Solar energy is mostly in demonstration phase.

Signs of more rapid development of renewable energy technologies are appearing in Canada. The federal government and some provincial governments have either instituted policies or are reviewing options to encourage renewable energy projects. A number of utilities are analyzing the cost effectiveness of installing dispersed electricity generation systems for their remote customers rather than continuing to extend their transmission network. Cases in point include B.C. Hydro, TransAlta Utilities, Ontario Hydro, Hydro Québec and Newfoundland Light & Power. Field testing is also being undertaken by non-utility organizations and companies.

3.1.2 Renewable Energy Options in India

Although renewable energy technologies (RETs) like biogas plants and improved cookstoves had been disseminated in India since the late 1940s, the renewable energy program started in right earnest only with the establishment of the Department of Non-conventional Energy Sources (DNES) in 1982 Later in 1992 DNES was converted into Ministry of Non-conventional Energy Sources (MNES) Until recently, RETs in India have been promoted through demonstration and R&D projects as well as large-scale dissemination projects/programs most of which were supported by government subsidies and financial incentives.

So far the contribution of renewable energy has been insignificant (not accounting for direct biofuel use in the rural areas) in the overall energy mix in the economy. There have been two major reasons for this: firstly, compared to the conventional energy sources, RETs have, except for a few biomass-based technologies, not been economically viable due to various technological and other constraints. The second reason for the poor penetration of renewables in India has been low budgetary allocations for their promotion. Between 1980 and 1992, the cumulative government expenditure in the renewable energy sector totalled Rs 11.55 billion, as against Rs 812 billion in the power sector, Rs 335 billion in the petroleum sector, and Rs 158.5 billion in the coal sector. Even in the 8th Plan (1992-97), allocation for the renewable energy sector represented only 0.8 percent of the total funds allocated to the energy sector. Another significant factor has been a lack of active linkage with the industry, either in R&D or in application, which would have brought private capital into the sector.

The biogas program had traditionally been the single largest renewable energy program, accounting for over half of the funds allocated. All other individual programs have received less than 10 percent of the funds. In terms of numbers, however, the dissemination of improved cookstoves has been the largest program followed by the biogas program. Biogas plants and improved cookstoves have enjoyed a fair amount of success and acceptability among rural households. However, there is scope for considerable improvement in the implementation of these programs.

Among other technologies, windfarms have emerged as a viable option in the power sector. As on March 1994, 114 MW of grid connected windfarms were operational. The performance of windfarms over the last five years shows an average reliability of 98 percent. The capacity utilization factor has been found to be as high as 30 percent in some locations. Estimates by the MNES place the ultimate wind energy potential in India at 20,000 MW. With the experience gained in the program, and the growing interest of private sector in this technology, wind energy can be expected to develop even more in the coming years.

Small hydro has evolved as another promising option for electricity generation, especially in remote hilly areas where the cost of grid electricity is prohibitive. Total potential in India is estimated at about 10,000 MW. Presently 148 small hydro projects totalling 110 MW have been completed and 166 projects aggregating to 202 MW are under implementation. The main obstacle in the promotion of this technology has been the high capital cost. It is expected that standard adoption of a canal or cluster approach, so as to achieve large volume turn over, and careful planning to achieve short gestation periods will bring down the costs.

The gasifier program in India was launched in 1986 by the DNES based on 3.7 MW wood based gasifiers of which over 1000 have been installed in the country. Given the large availability of biomass in India, biomass gasification offers significant potential for meeting the energy needs particularly in rural and remote areas The promotion of biomass gasification in future will be dependent on the development of the technology, improvement in the reliability of operation, operating and maintenance costs and price of biomass.

Among solar thermal technologies, water heating systems (for industrial use) and solar cookers are gaining popularity. However, in both these technologies, attention needs to be paid to product development, and they need to be made more compatible with end-user requirements

On the whole, though not all RETs are defensible purely on economic grounds as yet, environmental and social concerns, which are of equal importance in view of the need for sustainable development, make a case for their promotion. Thus, in order to promote RETs in a systematic manner, DNES was converted to a full-fledged Ministry (MNES) in late 1992. And, in

tune with the new policy of economic liberalization, MNES has adopted a comprehensive strategy and action plan for promoting RETs in India. The action plan shifted the focus of the programs from State-supported development and demonstration activities to market-oriented commercialization of technologies. The thrust of the strategy now is to provide a conducive policy environment and support mechanisms that would lead to increased participation of the private sector in the utilization of RETs. In order to encourage this process, a package of fiscal incentives and tax holidays has been introduced. The package includes 100 percent depreciation allowance, soft loans, reduced customs duties on imported materials and equipment, exemption from excise duty and sales tax, remunerative price for power fed into the grid, and facilities for wheeling and banking of power.

A separate financial institution--the Indian Renewable Energy Development Agency (IREDA)--set up in 1987 by the MNES plays a key role in implementing this package, by offering loans on soft terms to users and manufacturers of RETs. A few of the state governments and state electricity boards have also adopted guidelines and policies aimed at promoting renewable energy projects in the respective states.

3.2 Demand-side Management (DSM) Strategies

Demand-side management (DSM) is used to describe the actions of a utility, beyond the customer's meter, to alter the end-use of electricity--whether it be to increase demand, decrease it, shift it between high and low peak periods, or manage it when there are intermittent load demands--in the overall interests of reducing utility costs. DSM programs involve the implementation of measures that help the customers to use electricity more efficiently and in so doing reduce the customer's bills as well as the utility's cost. DSM can be achieved through the following.

- Improving the efficiency of various end-uses through better housekeeping, correcting energy leakages, system conversion losses etc..
- Developing and promoting energy-efficient technologies.
- Adopting soft options like time-of-use pricing, seasonal tariffs, interruptible tariffs etc..

3.2.1 North American Experience in DSM

DSM is, today, a multi-billion dollar worldwide industry. In 1991, the U.S. and Canadian utilities alone budgeted some $US 2 billion for DSM programs. Much of the attention to DSM in North America is devoted to conservation and load reduction programs. To date over 500 utilities have offered more than 1000 programs. The Electric Power Research Institute (EPRI) has estimated that strategic conservation will account for 69 percent of

the planned peak demand reduction from U.S. utilities through the year 2000. Canadian utilities expect DSM savings to amount to 12,565 MW, 60 percent of which is expected to come from strategic conservation programs.

The success of North American utility ventures into DSM can be attributed to four features (i) well designed programs; (ii) integrated resources planning; (iii) partnerships; and (iv) standards. The first-generation DSM programs implemented by electric utilities were low-cost, easy-to-implement programs such as residential audits, simple information dissemination, direct load control, and rate design. During the early 1990s weatherization programs became widespread in the U.S.. More recently, particularly in California, the North Eastern and North Western U.S., Ontario and British Columbia, utilities have begun to implement comprehensive second-generation programs incorporating packages of energy efficiency measures and multiple marketing and delivery techniques. Some of the important DSM initiatives undertaken by utilities include the following.

- Rebate programs promoting energy-efficient equipment, such as household appliances, lighting, motors etc..
- New construction market programs promoting implementation of conservation measures in the building at the time of construction for relatively small incremental costs New construction programs range from simple information programs to comprehensive service packages that include financial incentives, education and technical training for building owners, architects and developers. Several utilities provide financial incentives to the builders or homebuyers in order to reduce the up-front purchase price of an energy efficient home.
- Lessons from North American utility experience demonstrate that utility commitment, program targeting, customer acceptance, delivery mechanism, marketing effort, assistance of trade allies, financial incentives, information and education are key elements that are essential for the success of any DSM program.

3.2.2 Energy Efficiency and DSM in India

The Ministry of Power (MoP) is responsible for coordinating energy efficiency activities in India. Several studies carried out by the Government, multi-lateral institutes, research organisations, etc., have estimated 20-30 percent conservation potential in various consuming sectors.

According to the estimates of the 14th Electric Power Survey, demand for electricity is estimated to grow at a compounded annual rate of 8.3 percent during the period 1992/93 to 2011/12. Among the various consumer categories, demand is estimated to grow at an annual rate of 12.8 percent in the domestic sector and 9.8 percent in the commercial sector. Industrial elect...

demand is estimated to increase at a rate of 6.7 percent during this period, while growth in electricity demand for the agriculture sector is forecast to decline significantly after 2001/02.

Of the technological options available for end-use efficiency improvement, consumers will primarily consider those options which are cost effective. The three most commonly used approaches to estimating the cost effectiveness of an energy efficient measure are simple payback period (SPP), cost of energy saved (CES), and cost of peak generating capacity saved. SPP is defined as the ratio of the incremental capital cost of the energy efficient technology and the annual benefit to the consumer as a result of adopting that technology. The lower the payback for the option, the more attractive it is.

CES is the levelized cost of the energy efficiency measure per kWh saved. The lower the CES of a measure relative to the marginal cost of generation and supply, the more cost-effective is the efficiency improvement measure. Cost of measure per kW of peak generating capacity saved is calculated for a stipulated long term period, say 20 years For measures with a shorter life, equipment replacement costs are discounted and incorporated in the calculations. The energy efficiency measures which have a cost per kW of peak generating capacity saved that is less than the cost per kW of a new generating plant, must be evaluated by the utilities as a viable option in order to minimize costs of meeting their new demand. While the first two give the cost-effectiveness from the consumer's point of view, the third criterion is primarily to assist the utility to take a decision.

For various measures for efficiency improvements in different end-uses, estimates of simple pay back period, cost of measure per kW of generating capacity saved, and CES are provided in Table 1. It is evident that most of the options considered have a simple pay back period varying between 0.5 and 3 years. All the measures considered are cost effective when compared to a capacity cost of Rs 30,000/kW for new coal-based thermal power plants. Also, in terms of the cost of saved electricity, all the options are less that Rs 1.12/kWh, which is significantly lower than the long run marginal cost of generation and supply of electricity of Rs 1.73 to Rs 2.02 (1990/91 price level). In the industrial sector, rewinding and sizing of motors, and savings in electric arc furnaces are the most cost effective measures. In the domestic and commercial sectors, energy efficient lighting systems are attractive options, and in the agriculture sector, retrofitting of pumpsets has the most significant potential for electricity savings.

Electricity savings potential in various consuming sectors is estimated based on realistic participation rates as a result of favorable economics of the energy efficient technologies, discount rates assumed by the consumers, availability of energy efficient technologies, etc.. Savings potential is likely to be sensitive to market penetration rates. For instance, savings

increases from 14.2 percent to 18.2 percent in 2011/12, if the number of pumpsets retrofitted every year is increased from one percent to two percent of the total pumpsets in use. In the commercial sector, an increase in the market penetration rate for the CFL lighting option from 5 percent to 7.5 percent in 2001/02 onwards, results in an increase in savings from 10.8 percent to 11.1 percent in 2011/12.

It is estimated that the Indian power sector can save 6.29 percent of the total electricity demand by 1996/97 and upto 8.21 percent in 2011/12, through adoption of energy efficiency and DSM options. Maximum benefits are estimated to come from agriculture, residential, and commercial sectors. Demand for electricity under business-as-usual (BAU) scenario and energy efficiency scenario are compared in Table 2.

There is little doubt that India's electric power sector could gain from the implementation of energy efficiency and DSM programs. Technical potential and cost-effectiveness of various measures for improving end-use efficiency are well established. However, the actual efficiency gains remain far from being realized, due to a variety of technical, policy, institutional, and information related barriers. Some of the important barriers include high initial cost of energy-efficient equipment, limited availability of energy-efficient technologies, risk aversion by consumers, and lack of information and awareness among consumers. On the policy front, perhaps the most important barrier is the present electricity pricing policy of the SEBs. Electricity prices are regulated and based on historical cost of the utility. In fact, for most of the utilities, average revenue realized per unit is actually less than the average cost of supply. The extent of subsidies is particularly high for the agriculture sector at 80-100 percent, with subsidies for the domestic sector ranging between 40 and 60 percent. Such a pricing policy does not provide the consumers with the right signals and does not induce consumers to conserve electricity. Also, lack of utility commitment to DSM and to an integrated approach to power planning, is responsible for the slow progress in energy efficiency and DSM in India

3.3 Industrial Cogeneration

3.3.1 Cogeneration in North America and Canada

There has been considerable interest in industrial cogeneration activity in the past 15 years in North America, a trend that is expected to continue In the U.S., industrial cogeneration is expected to increase from 28,613 MW in 1991 to 63,554 MW in 2010. In Canada, expectations are that industrial cogeneration will climb to 4221 MW by 2010 from a current level just under 1000 MW. The extraordinary growth of industrial cogeneration, and, in particular, gas fired cogeneration, can be attributed to several factors. First, the technology itself has advanced in terms of efficiency, reliability and

sophistication. Second, utilities are facing increasing costs as the technical economies of large scale generation facilities have been reached and more stringent environmental controls place increasing cost pressure on conventional power generation technologies. Third, growing interest in protecting the environment and demands for greater energy efficiency have turned attention to cogeneration. Fourth, low natural gas prices have enhanced the commercial prospects of industrial cogeneration. And finally, governments are actively promoting cogeneration through various means, including requirements for provincially-owned electric utilities to purchase cogenerated power and tax benefits for cogenerators.

Governments in Canada and the U.S. have adopted markedly different paths to promote industrial cogeneration The U.S. has elected to design very specific legislation supporting cogeneration, whereas Canada relies on a market approach with tax incentives for specified cogeneration activities.

Until recently, the mainstay of the Canadian approach has been for governments to direct their publicly-owned electric utilities to increase the system share of non-utility generation in general, and cogeneration specifically, often by setting target guidelines. Because electric utilities are publicly-owned, compliance has not been an issue in Canada. Government intervention encouraging cogeneration has been most prominent in those jurisdictions offering the greatest cogeneration potential, those being Ontario--74 percent of projected cogeneration potential, Québec--11 percent and British Colombia-11 percent. In Canada, direct industry investment in cogeneration is encouraged through a special federal tax provision called Class 34, Accelerated Capital Cost Allowance. This tax incentive applies to assets that save energy or use renewable sources of energy. Basically, the mechanism allows the company to write-off eligible assets over three years--up to 25 percent in the first year, up to 50 percent in the second year, and the balance in the third year. In contrast, capital equipment without cogeneration potential receives either a six percent or 20 percent declining balance write-off.

Much of the cogeneration activity in the U.S. has been attributed to the Public Utilities Regulatory Policies Act (PURPA). The primary intent of PURPA has been to encourage cogeneration and small power production using non-conventional fuel sources. This legislation broadened the Federal Energy Regulatory Commission's (FERC's) role to include the establishment of rules guiding electricity pricing, electric power sales and wheeling by these parties in conjunction with the electric utility. FERC's guidelines specifically direct electric utilities to purchase all electricity from qualifying non-utility generators at reasonable rates not exceeding the utility's avoided costs. A 'qualifying facility' includes cogeneration facilities with capacity less than 80 MW for which at least 75 percent of the energy inputs must come from biomass, waste burning, renewable sources, or geo-thermal heat.

Table 1

Cost Effectiveness of Various Measures for End-use Efficiency Improvement

Energy Efficiency Measure	Simple Payback	Cost of Measure/kW Saved (Rs/kW)	Cost of Saved Electricity (Rs/kWh)
A. Domestic Sector			
Replace GLS by CFL	2.12	9 198	0.99
Replace GLS by FTL	3.65	3 360	0.36
Replace FTL by TLD	0.00	0	0.00
Moderate Efficiency Refrigerators	11.20	20 739	0.93
High Efficiency Refrigerators	13.57	25 136	1.12
Energy Efficient Fans	6.52	7 378	0.54
Energy Efficient ACs	3.32	5 016	0.31
B. Commercial Sector			
Replace GLS by CFL	1.06	10 278	0.74
Replace GLS by FTL	0.79	2 577	0.18
Replace FTL by TDL	0.00	0.00	0.00
Replace HPMV with HPSV	0.35	-4 248	-0.18
New HVAC System	1.82	11 110	0.48
C. Agriculture Sector			
Retrofitting of Pumpsets	1.64	5 076	0.12
Energy Efficient Pumpsets	3.56	11 036	0.25
D. Industrial Sector			
Rewinding, Sizing of Motors	0.55	10 231	0.38
High Efficiency Motors	1.80	15 385	0.57
Optimizing Industrial Pumps	2.43	21 259	0.79
Savings in Arc Furnaces	0.80	9 385	0.35

SOURCE: Tata Energy Research Institute.

Table 2

Sector-wise Demand for Electricity Under BAU and EE Scenarios

	Domestic	Commercial	Agriculture	Industry	Total
1996/97					
BAU	80 208	20 839	68 090	133 530	324 762
DSM	74 333	19 716	63 895	124 300	304 339
% savings	7.32	5.36	6.16	6.91	6.29
2001/02					
BAU	159 041	37 702	92 850	187 404	513 406
DSM	144 696	35 443	83 117	175 705	475 370
% savings	9.02	5.99	10.48	6.24	7.41
2006/07					
BAU	263 599	53 128	97 259	255 431	719 304
DSM	238 006	49 288	86 087	240 649	663 916
% savings	9.71	7.23	11.49	5.79	7.70
2011/12					
BAU	434 630	76 178	102 160	347 116	1 029 614
DSM	389 873	67 939	89 479	328 218	945 102
% savings	10.30	10.81	12.41	5.44	8.21

SOURCE: Tata Energy Research Institute.

Another important factor responsible for promotion of cogeneration in the U.S. is the adoption of integrated resource planning (IRP) by utilities. The element of importance in the context of cogeneration is that utilities must now also consider non-utility generation projects as supply-side alternatives and evaluate alternative strategies to their traditionally-owned and operated generation facilities. In addition, utilities must reconcile the environmental implications, and the benefits and costs of all options--demand and supply side--in meeting system load. IRP is being adopted in British Columbia, Alberta, Ontario, and Québec, to varying degrees, to help utilities counter increasing pressures from competing energy forms, government, regulatory authorities, and the public.

3.3.2 Cogeneration in India

The industrial sector presently accounts for almost 52 percent of the total electricity consumption in India. Several energy-intensive industry categories such as sugar, paper, textile, and fertilizer generate their steam requirements internally and also purchase electricity from the grid. Cogeneration of electricity and steam offers increased system and fuel efficiency to the industry. It reduces industry demand for utility power and the additional surplus, if any, could be sold to utilities. Cogeneration, thus, provides an alternative to utility power and reduces the overall emissions from the power sector.

While cogeneration systems are in use in some of the paper, pulp, and fertilizer industries in India, there are little efforts to optimize the steam and electricity requirements for various reasons. These include company investment criteria, unavailability of equipment, concerns about incremental costs, and above all government regulations.

Significant cogeneration potential has been identified in the Indian industrial sector. The National Productivity Council carried out a macro study in 1979 on the feasibility of cogeneration in Indian industries and estimated a potential of 421 MW in 28 of the 150 industrial units surveyed. It also estimated that over 1500 MW of additional power could be generated with marginal investments in cogeneration systems. A study carried out by the Inter-ministerial Working Group in 1983 estimated that the economic potential for cogeneration in the major industries in India is about 1500 MW. More recently, a study carried out the Tata Energy Research Institute in 1993, based on a detailed survey of 300 industrial units, estimated a total cogeneration potential of 7574 MW, of which the sugar industry alone was estimated to account for over 65 percent of the total identified potential (Table 3). Substantial potential also exists in the textile and paper industry.

Table 3

Cogeneration Potential in India
(MW)

Region	1991	1996	2001	2006	2011	2016	2021
Northern Region	2137	2823	4026	5910	8472	12153	17443
Western Region	1707	2303	3275	4756	6766	9642	13759
Southern Region	2828	3731	5301	7755	11093	15883	22763
Eastern Region	875	1178	1698	2501	3593	5164	7425
North-eastern Region	26	35	50	75	109	159	230
Total	7574	10070	14350	20997	30033	43000	61621

SOURCE: Tata Energy Research Institute.

While the energy conservation potential through the application of cogeneration systems is well appreciated, there are several technology, regulatory, financial, and economic barriers that constrain the use of cogeneration.

Technology. High pressure boilers and turbine accessories are not available in sufficient quantities indigenously and are presently imported. There is also a considerable technological gap between what is available in India and the various advanced configurations and systems available in the developed countries.

Legislative constraints. Currently, there is no legal framework for the purchase of surplus cogenerated power. Very few SEBs have encouraged cogeneration, and only three or four have arrangements for wheeling and banking of cogenerated power.

Pricing policy. There is no clear pricing policy for the purchase of power. The tariff for cogenerated power should, ideally, be set at the avoided cost of new capacity added for meeting demand.

Grid related problems. Parallel operation of a generating unit presents several concerns for a utility. These include safety, power quality, reliability, protection of facilities, and planning or operating problems. Three may also be problems of grid synchronization.

In recognition of the benefits from cogeneration, the Government of India (GOI) has endeavored to facilitate its development in India. The MNES in 1994, announced financial incentives for demonstration of cogeneration projects in sugar mills and for preparation of detailed project reports for bagasse-based cogeneration. The MoP, under their policy decision to encourage private sector participation in power generation, is also promoting cogeneration.

3.4 Clean Coal Technologies

Clean coal technologies (CCTs) offer the potential for significant reduction in environmental emissions when used for power generation. These technologies may be used in new, as well as existing plants and are therefore an effective way of reducing emissions in the world's ageing inventory of col-fired generating units. Several of these systems are not only very effective in reducing SO_2 and NO_x emissions but, because of their higher efficiencies, they also emit lower amounts of CO_2 per unit of power. CCTs can be used to reduce dependence on foreign oil and ot make use of a wide variety of available coal types and quality.

In India, coal constitutes about two-thirds of total commercial energy consumption. The power sector and industries together account for 94 percent of total coal consumption. Indian coal is characterized by high ash content and low sulphur content. Over 60 percent of the coal reserves are of inferior quality with gross calorific value (GCV) of 4000 kcal/kg or less. The efficiency of coal conversion in Indian thermal power stations is low; relative to the design gross efficiency of 36 percent, the average gross conversion efficiency is about 28 percent and the average net efficiency is only 25 percent. About 75 percent of the country's thermal capacity operates at efficiencies below 30 percent. The environmental consequences of increased coal use are today recognized by India's energy and environmental planning agencies and there is a growing realization that coal-related environmental problems must be controlled in the future through use of CCTs in the various consuming sectors.

CCTs can be installed at any of three stages in the fuel chain, or in a fourth manner that departs from the traditional method of coal burning.

Pre-combustion. Sulphur and other impurities in coal are removed before the coal reaches the boiler. This includes options such as physical cleaning.

Combustion. Pollutants inside the combustor or boiler are removed while the coal burns. Various technologies of fluidized-bed combustion are available to reduce emissions while retaining efficiency

Post-combustion Flue gases released from coal boilers are cleared in the ductwork leading to the smokestack or in advanced versions of today's scrubbers.

Conversion. The combustion process is bypassed altogether, coal is converted into a gas or liquid that can be cleaned and used as a fuel. The options available include Integrated Gasification Combined Cycle (IGCC), Pressurized Fluidized-bed Combustion (PFBC) technologies, etc.,

3.4.1 Canadian Experience with CCTs

All coal-fired utility boilers in Canada are pulverized-fired with unit size ranging from 25 to 500 MW. Emissions from existing units are monitored by provincial authorities, whereas new sources are designed to comply with federal guidelines that currently specify 258 ng/J for SO_2, 258 ng/J for NO_x, and 43 ng/J for particulate matter. As a signatory to the Convention on Global Warming, Canada is committed to limiting national CO_2 emissions to 1990 levels. Consequently, reliable cost-effective technology that maximizes the conversion of coal to electricity is a priority consideration in the selection of all new coal-fired generators.

A number of innovative CCTs are being implemented or are planned for future installation by Canadian utilities. These include a variety of systems for retrofit to existing units and emerging processes for new units. Two new units, one rated at 300 MW lignite fired and other 450 MW on high-volatile bituminous coal, with low NO_x combustion and sulphur capture systems are under construction.

FBC's potential to minimize both SO_2 and NO_x emissions makes it attractive for Eastern Canada, where the only indigenous fuel available is coal, most of it containing 3-10 percent sulphur. To meet the challenge of using indigenous coal in an environmentally acceptable manner, the Canadian federal government sponsored a demonstration of fluidized bed combustion technology in a heating plant at Summerside, Prince Edward Island. A small-scale, electric utility FBC demonstration has been constructed at Chatham, New Brunswick. The objective of this venture was to establish the viability of circulating fluidized bed combustion (CFBC) technology for generating electricity from high sulphur coal. In October 1989, Nova Scotia Power Incorporated signed contracts for a single 165 MW CFBC unit. FBC was selected because of lower waste disposal costs, better NO_x control, and greater fuel flexibility. Canadian utilities have in the recent past carried out two projects to evaluate the benefits and cost-effectiveness of coal gasification technologies. The results of all these demonstration projects show that CFBC has a substantial advantage in unit capital cost, but IGCC has the best efficiency and the most favorable operating and maintenance costs. Based on these studies, any application of IGCC in Canada is likely to be driven by environmental rather than economic considerations.

3.4.2 Potential of CCTs in India

In India, coal-based thermal power generation will continue to grow to meet increasing electricity demand. Innovative technical options now exist, which can be used for modification of existing conventional coal power plant to significantly improve their cost-effective environmental performance. Technologies which could be used on the fuel side include conventional coal washing, which can result in an increase in the efficiency of the power station

and a reduction in ash handling. Washing costs are estimated to be in the range of Rs 100-150 per tonne, which is more than offset by transportation cost savings, even if no credits are taken for availability improvements in the power plant. Combustion modification processes such as stage burners, reburning etc. could be introduced. Post-combustion clean-up technologies include conventional and advanced flue gas scrubbing.

Integrated technologies based on PFBC, coal gasification and Molten Carbonate Fuel Cells (MCFCs) are environmentally superior options with high efficiency and consequently with less CO_2 emissions. Large-scale implementation of integrated technologies would result not only in reduction of SO_2 and NO_x but also lower CO_2 emissions.

FBCs seem to be the best alternative to pulverized coal boilers in the medium term. FBCs cost as much as pulverized coal boilers, require less annual expenditure, are more efficient, and have lower specific emissions of both CO_2 and NO_x. They are, however, presently available only in capacities up to about 150 MW. There is an urgent need to immediately introduce 100 MW CFBC's at a number of stations in country, so as to start gaining operating experience.

In the long term, IG-MCFC is potentially the most efficient advanced coal-to-electricity technology. However, it is still in the developmental stage and at least a decade away from demonstration level operation. As expected, the largest uncertainties, both with respect to overall efficiency and expected cost of electricity, are associated with this technology, the single largest uncertainty being the capital cost of MCFC.

PFBC technology is next, both in terms of efficiency and electricity cost. The uncertainties associated with PFBC cost and efficiency parameters are less when compared with IG-MCFC systems, and the single largest uncertainty is in the cost of gas clean-up devices which are capable of conditioning the PFBC flue gas to meet gas turbine inlet standards.

3.5 Transmission and Distribution Loss Reduction

High T & D loss is an issue of major concern for the electric utilities in India. Losses have increased from about 15 percent in 1966/67 to 21.74 percent in 1986/87, and have since increased to about 23 percent. Of the total 23 percent T & D losses, four percent corresponds to losses in the transmission (400 kV, 220 kV, 132 kV and 66 kV) system and the remaining 19 percent to losses in the distribution (33 kV, 11kV and 400 kV) system. The impact of the excessive T & D losses in the Indian power system is two-fold. Firstly, they result in under-utilization of the total energy that is being generated, which is unpardonable considering the energy shortages that the country is currently facing. The situation is further aggravated by a flowing financial resource constraint on the construction

of additional generating capacity, required to meet projected demand. Secondly, the energy wasted due to T & D losses much be compensated for up new generating stations (in all probability fossil fuel based thermal) with environmental degradation problems due to emission of greenhouse gases and other associated problems.

Perhaps the single most important factor responsible for high T & D losses is the lack of adequate investment by the electric utilities in the T & D systems. In the past, the investments in generation have gained priority over investments in T & D. Investments in T & D in the various five year Plans in the past have been only 40-50 percent of the total investments in generation. Technical factors responsible for the large magnitude of T & D losses include:

i) lack of systematic distribution system planning which invariably results in overloading of the system;

ii) existence of many stage of transformation, viz. 132/33 kV, 66/33 kV, 33/11 kV, 11/0 kV;

iii) adoption of inappropriate distribution technology, viz. low voltage distribution system (LVDS) which is suitable for countries with high load densities and not for a large country like India with loads sparsely spread over wide areas;

iv) inadequate reactive compensation; and

v) poor quality of electricity meters and lack of adequate calibration facilities.

Another factor responsible for high distribution losses in non-technical losses occurring on account of defective metering, un-metered power supply, pilferage, etc. Reduction of T & D losses is today is priority area for the SEBs. It is expected that the losses should be reduced by one percent point every year and gradually brought down to 15 percent.

4. Model Results

4.1 Model Scenarios and Constraints

The following eight scenarios were analyzed, using the MARKAL-ELGEM model, to determine the cost of each scenario and its associated environmental implications.

<u>Base case development scenario</u>. This case represents a 'Business-as-usual' development strategy. Other than the limitations on expansion of hydroelectric generation capacity up to 80 GW in 2021 natural gas utilization restricted to maximum of 14.7 billion cubic meters per annual; and new nuclear capacity restricted to an additional 27 GW by 2021, this is an unconstrained, least-cost development scenario which meets all the projected electricity demand.

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Reference case scenario. The unconstrained development scenario described in the Base Case is clearly unrealistic for India. In particular, the investment required to finance the implied capacity expansion would necessitate an unprecedented diversion of national income to the power sector, assuming that the financial capital for power sector development was to be provided by the government. For purposes of comparison with alternative development scenarios, it was decided to generate a Reference Case scenario based on a realistic set of initial constraints for power sector development. The structure of this scenario is the same as the Base Case, except that:

- a financial constraint is imposed limiting capital investment in the power sector to historical levels of 3.2 percent of gross domestic product GDP forecast for India.

- a coal constraint is imposed limiting coal available for electric power generation to 405 MT in 2011 and 650 MT in 2021. This constraint is imposed to capture both the physical capabilities of the mining and transportation network to provide coal volumes, and the declining quality of available coal; and

- renewable sources of electricity supply are assumed as part of the available generation mix.

DSM scenario. This scenario makes available to the system a number of plausible DSM options. Electricity demand under this scenario is reduced to the extent that energy-efficient technologies are adopted for various end-uses

CCT scenario. From the list of possible CCTs, Integrated Gasification Combined Cycle (IGCC), Pressurised Fluidized Bed Combustion (PFBC) and Atmospheric Fluidized Bed Combustion (AFBC) are made available under this scenario, owing to their cost competitiveness and technical availability over the projection period and their potential for meeting emission control requirements.

Cogeneration scenario. This scenario makes available to the system cogeneration potential in the industrial sector in India.

Reduced T & D loss scenario. This scenario evaluates the system-wide impacts of reducing T & D losses from the present 23 to 15 percent.

Optimistic (IRP) scenario. This scenario represents the outcome of an Integrated Resource Planning approach to electric power development, in which all supply- and demand-side options for meeting the demand for electricity services are compared on a least-cost basis. This planning paradigm is finding increasing acceptance among North American electric and gas utilities as an efficient and cost-effective approach to development planning.

BAU with all options plus gas import. Building on the optimistic scenario, this scenario assumes that : (1) an integrated approach to electric power development is put in place; (2) there are no financial constraints on India's electric power development; and (3) India is able to import gas from the Middle East to an upper limit of 30 billion cubic meters per year.

Details of the model results for these eight scenarios are provided in Tables 4, 5 and 6.

4.2 Scenario Comparisons

With the notable exception of the optimistic scenario, there is not a clear winner among the development scenarios described above. From a policy and planning standpoint, the choice of priorities among the various options will, therefore, depend on the decision criteria used for assessment. This section provides a comparison of scenario results on the basis of three candidate criterion: (i) capacity shortfall; (ii) SO_2, NO_x and CO_2 emissions; and (iii) total electric power system costs.

Capacity Shortfall

If satisfying demand is an overriding priority in system development, then one important criterion for selection among the various alternative scenarios could be to minimize capacity shortfall. Table 6 provides a comparison of capacity shortfalls under the reference and alternative scenarios. All the alternative scenarios result in a reduced capacity shortfall relative to the Reference Case. Under the DSM, reduced T & D losses, and optimistic scenarios, capacity short-falls are eliminated until the 2006 reporting period. That is, all projected demands for electricity services are met under these scenarios. Under the Reference plus all Options scenario, the shortfall is eliminated till the year 2010 and is only 44 percent of the Reference Case shortfall by 2021.

All scenarios with investment constraints result in capacity shortfalls, ranging from 27 to 70 percent. While each individual option (CCTs, DSM, cogeneration, etc.) indicates shortfalls of around 50-60 percent, the combination scenario with investment constraints indicates a substantially reduced shortfall of 27 percent. When the investment constraint is removed, shortfalls are eliminated. Assuming that funds estimated under the constrained scenario would indeed be made available by the government, the obvious conclusion would be that additional funds would have to be raised from the private sector, both domestic and foreign, in order to eliminate the capacity shortfall and satisfy all the demand.

Emissions

The ten-fold increase in the size of the India electric power sector by 2021 under the Reference Case, combined with the continued dominance of coal-fired generation in the system capacity mix, raises the concern of unconstrained growth in environmental emissions associated with electricity generation. In the

Reference Case, annual CO_2 emissions increase to 1128 MT in 2021, almost four times the projected level for 1996 (Table 7). This is only one-half the growth anticipated in the unconstrained Base Case projection, but the improvement in emissions is at the cost of unsatisfied electricity demand.

The desire to minimize emissions from the electric power sector is a second criterion for choice among the development options examined in this study. Not surprisingly, the Optimistic scenario, representing an integrated system planning paradigm, is the preferred option from the standpoint of limiting CO_2 emissions. If the concern is directed to regional emissions--SO_2, NO_x, particulates--rather than CO_2, then the CCT scenario is the preferred option, followed by the Optimistic scenario.

Total System Costs

A third decision criterion, which could be applied to these development options, is minimization of total system costs, defined here as the cost of power system development and the cost of unsatisfied demand.

One of the more insightful results of this analysis is that using all available options to satisfy power demand results in a significant decline in total installed system cost, whether a financial constraint is imposed or not. As shown in Table 8, simply introducing the system options examined in this study to the unconstrained Base Case lowers total system costs by some 18 percent, a significant financial savings of Rs 80,031 crores. While imposition of a financial constraint lowers further as spent system cost, the results indicate that there are large cost and emissions savings that would result from adoption of the IRP paradigm for Indian electric power development.

5.0 Conclusion

This study has examined a number of options available to the Indian power sector in meeting the country's rapidly growing demand for electricity. Pursuing these options will require considerable change in the structure, operation, regulation, and decision-making practices currently governing electric power development in India. Continuation of current practices suggests a future of growing unsatisfied electricity demand, and declining electricity system reliability.

There is much that can be done to ameliorate these problems, even in the context of the financial and energy constraints facing the country. Adoption and implementation of IRP in the power sector, movement towards cost-based pricing principles, and creation (and empowerment) of an independent regulatory authority to oversee the future expansion and operation of the power system are all important steps towards a secure energy future for India

Table 4

Comparision of Various Scenarios During 2001

	Base Case	Reference Case	DSM	CCT	Co-generation	Reduced losses	Reference plus all plus gas imports	BAU - plus all
Installed Capacity (MW)								
Coal	81768	67328	63086	66854	62393	67033	59632	61084
Nuclear	4831	6131	6131	6131	4831	6131	4831	4831
Natural Gas	20355	20483	19789	20573	20651	19789	19889	20439
Hydro	35828	35261	37624	35459	34737	38018	33335	32952
Others	0	0	0	0	9427	0	1900	312
Subtotal	142782	129204	126630	129017	132039	130971	19587	119618
% Hydro	25.1%	27.3%	29.7%	27.5%	26.3%	29.0%	27.9%	27.5%
Capacity Shortfall	0	8566	0	8567	7323	0	0	0
% Gen. Subtotal	0.0%	6.6%	0.0%	6.6%	5.5%	0.0%	0.0%	0.0%
Total Capacity Reqd.	142782	137769	126630	137584	139363	130971	119587	119618
Installed Generation From (MW)								
Decentralized Power	0	3200	2200	3200	3200	2200	1240	1120
Demand-side Management	0	0	4893	0	0	0	4893	4893
Cogeneration	0	0	0	0	9427	0	1900	312
CCTs	0	0	0	1669	0	0	0	0
Energy Resource Consumption								
Hydro (MW)	18774	18405	19820	18523	18107	20056	17280	17051
Coal ('000 tonnes)	256251	246024	210184	243493	228564	215444	208756	208732
Natural Gas (million m^3)	12490	12558	12193	12836	12646	12193	12245	12534
Fuel Oil ('000 m^3)	1962	1845	1568	1784	1702	1620	1548	1555
Nuclear Fuel ('000 kg U)	2294	3122	3122	3122	2446	3122	2446	2446
Environmental Emissions								
Particulates (tonnes)	4671239	5369262	4785887	5340708	5287901	4606628	4931076	4788019
CO_2 ('000 tonnes)	457930	440645	379375	436867	411291	388283	377018	377593
SO_2 ('000 tonnes)	2532	2435	2090	2371	2270	2141	2078	2080
NO_x ('000 tonnes)	2413	2322	1996	2269	2165	2043	1984	1986
Nuclear Waste ('000 m^3)	26630	36247	36247	36247	28401	36247	28401	28401

Table 5

Comparision of Various Scenarios During 2006

	Base Case	Reference Case	DSM	CCT	Co-generation	Reduced losses	Reference plus all plus gas imports	BAU - plus all
Installed Capacity (MW)								
Coal	133626	91502	94415	96892	91425	98392	86217	86404
Nuclear	4751	12051	12051	12051	10751	12051	10751	4751
Natural Gas	21036	21011	19947	21100	21179	19947	20490	36782
Hydro	41177	46860	47645	44080	43027	47645	42244	39147
Others	0	0	0	0	13799	0	6272	793
Subtotal	200590	171424	174057	174123	180181	178035	165974	167877
% Hydro	20.5%	27.3%	27.4%	25.3%	23.9%	26.8%	25.5%	23.3%
Capacity Shortfall	0	18306	577	15961	13217	3240	0	0
% Gen. Subtotal	0.0%	10.7%	0.3%	9.2%	7.3%	1.8%	0.0%	0.0%
Total Capacity Reqd.	200590	189730	174635	190084	193398	181275	165974	167877
Installed Generation From (MW)								
Decentralized Power	0	4800	3750	4800	4800	4800	1500	1500
Demand-side Management	0	0	7250	0	0	0	7076	7250
Cogeneration	0	0	0	0	13799	0	6272	793
CCTs	0	0	0	12177	0	0	6439	0
Energy Resource Consumption								
Hydro (MW)	21146	25087	25306	23421	22806	25557	22350	20495
Coal ('000 tonnes)	395251	320000	291816	320000	320000	310780	282385	299496
Natural Gas (million m^3)	12761	13716	12628	14084	13827	12628	12473	21036
Fuel Oil ('000 m^3)	3123	2480	2270	2207	2481	2420	2041	2304
Nuclear Fuel ('000 kg U)	1926	6203	5785	6203	5527	4636	5527	2408
Environmental Emissions								
Particulates (tonnes)	4847121	5173031	4482879	4833057	5173227	4773921	4639175	5133851
CO_2 ('000 tonnes)	693645	568188	518439	568955	568430	550503	501976	548118
SO_2 ('000 tonnes)	3857	3148	2869	2857	3149	3049	2634	3029
NO_x ('000 tonnes)	3669	2998	2735	2781	2998	2905	2539	2875
Nuclear Waste ('000 m^3)	22363	72015	67161	72015	64169	53829	64169	27955

Table 6

Comparision of Various Scenarios During 2021

	Base Case	Reference Case	DSM	CCT	Co-generation	Reduced losses	Reference plus all plus gas imports	BAU - plus all
Installed Capacity (MW)								
Coal	477209	191429	191388	216691	191401	191392	207171	341336
Nuclear	4690	28490	28490	28490	28490	28490	28490	4690
Natural Gas	24813	22778	22616	22903	23470	22616	23734	81891
Hydro	53960	76460	76020	75820	74098	76026	69020	52290
Others	0	0	0	0	45475	0	37925	22229
Subtotal	560672	319157	318514	343904	362935	318525	366340	502436
% Hydro	9.6%	24.0%	23.9%	22.0%	20.4%	23.9%	18.8%	10.4%
Capacity Shortfall	24878	224584	174700	198686	185257	190520	98691	1611
% Gen. Subtotal	4.4%	70.4%	54.8%	57.8%	51.0%	59.8%	26.9%	0.3%
Total Capacity Reqd.	585550	543741	493214	542590	548191	509045	465032	504047
Installed Generation From (MW)								
Decentralized Power	0	9600	9600	9600	9600	9600	9600	6600
Demand-side Management	0	0	19500	0	0	0	19500	19500
Cogeneration	0	0	0	0	45475	0	37925	22229
CCTs	0	0	0	134011	0	0	76142	3763.2
Energy Resource Consumption								
Hydro (MW)	26901	42431	42167	42047	41032	42171	38003	27979
Coal ('000 tonnes)	1393503	650000	650000	650000	650000	650000	650000	1085325
Natural Gas (million m^3)	14700	14700	14700	14700	14700	14700	14700	44700
Fuel Oil ('000 m^3)	11329	5240	5237	2041	5238	5237	3437	8740
Nuclear Fuel ('000 kg U)	1620	14751	14751	14751	14751	14751	14751	2131
Environmental Emissions								
Particulates (tonnes)	9420847	5791807	5814010	4715235	5807030	5811684	5164566	7822208
CO_2 ('000 tonnes)	2385795	1128628	1128574	1127785	1128591	1128580	1128233	1924912
SO_2 ('000 tonnes)	13368	6296	6295	2993	6298	6295	4433	10657
NO_x ('000 tonnes)	12683	5979	5980	3535	5979	5979	4596	10095
Nuclear Waste ('000 m^3)	18803	171264	171264	171264	171264	171264	171264	24737

Table 7

Scenario Comparisions
Capacity Shortfall
(MW)

Year	2001	2006	2011	2016	2021
Base Case	0	0	0	0	24877
Reference Case	8565	18305	45745	105777	224584
Demand-side Management	0	577	12472	67759	174700
Clean Coal Technology	8567	15961	45291	96317	198686
Cogeneration	7323	13216	35303	84490	185256
Reduced Losses	0	3239	26999	81510	190519
Reference Plus All Options	0	0	0	17575	98691
BAU Plus All Options	0	0	0	0	1611

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 8

Scenario Comparisions
Particulate Emissions
('000 tonnes)

Year	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Base Case	4943.6	4671.2	4847.1	5843.2	7447.1	9420.8	1.9
Reference Case	4372.9	5369.3	5173.0	4755.3	5139.7	5791.8	1.3
Demand-side Management	4377.8	4785.9	4482.9	4786.8	5159.8	5814.0	1.3
Clean Coal Technology	4357.9	5340.7	4833.1	4854.9	4462.9	4715.2	1.1
Cogeneration	4896.9	5287.9	5173.2	5208.1	5165.9	5807.0	1.2
Reduced Losses	4257.4	4606.6	4773.9	4766.7	5157.7	5811.7	1.4
Reference Plus All Options	4673.5	4931.1	4639.2	4704.7	4802.9	5164.6	1.1
BAU Plus All Options	4673.5	4788.0	5133.9	5720.5	6458.8	7822.2	1.7

SOURCES: ELITE, December 1994, Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Chapter 1

INTRODUCTION

1.1 Project Origin

The Canadian International Development Agency (CIDA) in conjunction with the Conference Board of Canada has initiated a program to stimulate linkages between Canadian and Indian organizations and to foster long-term business relationships. The program is called the Canada-India Institutional Linkage Program.

Because research institutes are seen to play an important role in bridging information gaps and, therefore, have an integral role in developing business linkages. Keeping this in view the Conference Board of Canada selected the Canadian Energy Research Institute (CERI) and the Tata Energy Research Institute (TERI) to undertake joint research on India's electricity sector.

Both research institutes have notable achievements and strong backgrounds in the issues that face the electric power sector. CERI's most recent undertakings include four studies by Morgan MacRae, *Critical Issues in Electric Power Planning in the 1990s*, (CERI Study No. 35) *New Coal Technology and Electric Power Development* (CERI Study No 38), *Coal in Canada* (CERI Study No. 40), and *Realizing the Benefits of Community Integrated Energy Systems* (CERI Study No 45); a study by Barbara Baker and Ellen Battle, *Demand-Side Management for Electricity: Pushing Back Barriers* (CERI Study No. 43); and a study by Anthony Reinsch and Ellen Battle, *Industrial Cogeneration in Canada: Prospects and Perspectives* (CERI Study No. 24)

TERI's recent accomplishments include the following studies related to the Indian power sector; "Study of coal and oil consumption in Panipat thermal power", "Reducing the transmission and distribution losses in Madhya Pradesh", "Energy conservation measures in the domestic sector", "Energy efficiency of domestic appliances", "Estimation of capacitor requirement in the northern region", "Human resources development in Madhya Pradesh Electricity Board", and "Singrauli Regional Environmental Rehabilitation Program".

1.2 Project Aims

CERI and TERI have been entrusted with the task of examining the critical issues in India's electric power sector and reviewing strategies for meeting India's electricity needs in the least cost and most environmentally-sensitive manner.

India's electricity sector can be characterized as one caught between environmental challenges and its country's stark economic, social, and political realities. On the one hand, Indian electric utilities are being pressured to (i) pursue generation technologies which are as environmentally benign as possible; (ii) ensure that their customers are using electricity as efficiently as possible, and (iii) retrofit existing generation capacity with equipment to either remove or reduce harmful emissions that would otherwise be emitted into the environment. On the other hand, the Indian electricity sector's ability to match these laudable objectives is limited by the need to develop their economy, their poor financial state and that of their customers, and the mix of central and state controls over the electric power sector.

Such a preamble serves to caution against a myopic review and recommendation of North American solutions to North American electricity sector problems without recognition of Indians' unique circumstances. That having been said, North American utilities have achieved some degree of success at meeting environmental objectives and offer resolutions that merit review, albeit with a judicious eye toward Indian solutions It is pertinent, then, to begin by reviewing the current situation of the electric power sector in India, providing some history and discussing current prospects

1.3 The Status of India's Electric Power Sector[1]

India's electric power balance has moved from one of surplus in the 1960s and early 1970s to one of shortages, with the prospectus for shortages destined to become even larger A shortfall of 12,000-14,000 MW is estimated for 1996-97, when electricity peak demand is expected to reach around 75,000 MW

Though the progress of the power sector during the past four decades has been substantial – from production levels of 2300 MW in 1950 to 69618 MW as of March 31, 1992 – estimated increases in demand and the financial situation of the electricity sector lead to dismal predictions of the ability of the power sector to meet demand in the future Demand per capita, which was a mere 15 kWh in 1950, has grown to 236 kWh in 1989-90 Already in 1991-92, the overall peak and energy deficits in India were 17 7 percent and 8 5 percent, respectively. The end result is that brown outs and/or involuntary load shedding have become prevalent

1 3 1 Institutional Structure

1 3 1 1 The Status Quo

Like most sectors of India's economy, the electric power sector and electricity use are heavily influenced by the government. The Central Electricity Authority (CEA) in association with the Ministry of Power of the Government of India (GOI), largely control the development of generation,

transmission, and distribution facilities due to the fact that it is the GOI that generates and distributes funds for these projects. In the 1970s, the central government established two electricity corporations, the National Thermal Power Corporation (NTPC) and the National Hydroelectric Power Corporation (NHPC),[2] whose primary function is to build and operate large power plants and supply power in bulk to state power systems using state-of-the-art equipment and the most qualified technical staff.[3]

Nuclear power plants come under the direction of the Department of Atomic Energy; policies for nuclear power development fall under the purview of the Atomic Energy Commission; and safety is monitored by the Nuclear Power Regulatory Commission.[4]

The ownership and operation of electric utilities lies predominantly with the State Electricity Boards (SEBs) who are responsible for the construction and operation of the electricity system. While price setting is recognized under the Electricity Supply Act as the purview of the SEBs, the state governments' have an advisory role in policy making and tariffs setting and design.

1.3.1.2 Rehabilitation of the Institutional Structure

The GOI has implemented policy changes aimed at moving the Indian economy away from central planning and toward market-based economic development. The evolution is a gradual one, however; and will require considerable direct government intervention to address the current array of challenges facing the electric power sector.

The New Industrial Policy, announced in July 1991, loosened the government hold over the electric power sector by allowing for the private sector generation and sale of electric power. The 'incentive' package provided to private companies includes the ability to: (1) maintain a debt/equity ratio of up to 4:1, with no more than 40 percent of the financing from Indian financial institutions; (2) hold up to 100 percent foreign equity; (3) earn 5 percent rate of return on their investments, above the central bank rate of 3 percent; and (4) cover both fixed and variable costs through a two-part tariff structure. To expedite the bureaucratic process, an Investment Promotion Cell in the Ministry of Power was developed to speed the approval process.

On February 27, 1993, a five-year tax holiday for new power plants was introduced to encourage foreign investors to finalize their proposed plans of more than $1 billion worth of power projects.[5]

While these are noteworthy improvements, over 90 percent of the electric power sector is still owned and operated by the central and state governments, who control or strongly influence all aspects of utility operations from plant construction to fuel acquisition, T & D networks, price setting and

electricity allocation. Private power generation projects must still be approved by the central government, and prices and rates of return are still set by the state governments; only now it appears that the central government will also set prices for the private companies. The control of transmission and distribution will be retained by the respective state government. Even if they attract investment and subsequent construction of generation capacity by private developers, the T & D system that has caused power bottlenecks in the past will likely limit delivery of this additional power.

Several other matters are still unclear, namely the status of well-intentioned and seemingly successful 'poverty alleviation programs' such as the Rural Electrification Program (REP) (see Section 1.3.7) and support for price subsidization of agricultural and domestic customers (see Section 1.3.8.1). It is unlikely that the central and state governments will abandon support of REP or of preferential rates for agricultural and domestic customers. In the end, while steps have been taken towards a market approach, both state and central governments have much ground to cover in re-orienting the government control of the electric power sector currently in place in India.

1 3 2 Installed Capacity

India's generating capacity comprises a mix of hydro, coal-fired thermal, oil-fired thermal, gas-fired thermal, and nuclear plants (see Table 1 1, for regional comparisons, consult Table A.1 in Appendix A).

Table 1.1

Installed Capacity Mix of Utilities in India

Year	Hydro		Thermal		Nuclear		Total
	(MW)	(%)	(MW)	(%)	(MW)	(%)	(MW)
1950	559	(32.65)	1 153	(66 34)	-		1 712
1960/61	1 917	(41 19)	2 736	(58.80)	-		4 653
1965/66	4 124	(45 68)	4 903	(54 31)	-		9 027
1970/71	6 383	(43 39)	7 906	(53 74)	420	(2 85)	14 709
1975/76	8 464	(42 07)	11 013	(54 74)	640	(3 18)	20 117
1980/81	11 791	(39 02)	17 563	(58.12)	860	(2.84)	30 214
1985/86	15 472	(33 08)	29 967	(64.07)	1 330	(2.84)	46 769
1990/91	18 753	(28 38)	45 768	(69 25)	1 565	(2 37)	66 086
1991/92	19 194	(27 80)	48 086	(69 62)	1 785	(2.58)	69 065

SOURCES (i) Public Electricity Survey, All India Statistics, General Review 1991-92, Central Electricity Authority, New Delhi.

Over the last several decades, there has been an increasing reliance on thermal facilities in contrast to the earlier preference to build hydro facilities. The share of hydro capacity in total installed capacity has declined from 43

percent in 1970/71 to 28 percent in 1991/92, while the share of thermal capacity has increased from 54 percent to 70 percent during the same period.

The shift to thermal has many foundations:

- thermal facilities, in general, have shorter lead times relative to hydro facilities thereby allowing a more expedient response to increases in demand;

- coal represents India's major fossil fuel energy resource--as of 1990, the proven and indicated coal reserves were estimated at 138 billion tonnes; approximately 20 percent of this was coking coal and the remainder is non-coking coal. In comparison, the proven and indicated reserves of crude oil and natural gas were only 757 million tonnes and 686 billion cubic metres, respectively;[6]

- hydro facilities have suffered from inter-state disputes on water sharing, rising costs, inadequate funding, delays in decision-making on land acquisition, non-standardization of unit size and plant design, inadequacies in construction management, contractual problems, environmental problems, concerns regarding the relocation of thousands of people, and remote and geologically unstable locations.[7]

Coal-fired generation represents the largest portion of thermal generation. As of March 31, 1992, coal-fired generation capacity totalled 48108 MW or over 95 percent of total thermal power generation. Since the 1960s, coal-fired power plants have undergone two major structural changes. The first is an increase in the size of the operating units, affording higher operating efficiencies and lower capital and operating costs. Until 1960, the largest size in use was a set of 90 MW plants; today, 210 MW and 500 MW sets have become common. Of the 281 thermal units operating in the country as on March 31, 1989, 55 units were of 110/120 MW capacity, 78 units were of 200/210 MW capacity, and 5 units were of 500 MW capacity.[8]

The second change has been a shift in the location of the plants. Earlier, power stations were constructed close to load centres. Now the preference is to locate the plants near pithead locations as moving large quantities of coal from the pithead to a plant poses formidable operational problems--access to an overburdened railway system and heavy investments in new rail carrying capacity being principal among them. However, the concentration of power plants at the pithead carries its own environmental challenges, such as the concentration of emissions and additional demands on an already overburdened T & D network (see Section 1.3.4).

India's reliance on coal is expected to continue as:

- coal represents an inexpensive, major fossil fuel resource; and

- the politics and economics of domestic coal in relation to producing and/or importing other energy sources and altering the electrical infrastructure to accommodate changes in primary fuels make coal preferable at this juncture.

Despite the comparative advantage of coal-fired generation; it will likely prove difficult for the Indian electric power sector to discount the overwhelming untapped hydroelectric potential in the future. Out of a resource potential 89,830 MW (assuming a 60 percent load factor), only 13 percent is developed.[9] The intent to exploit this resource is clearly reflected in both the development of the National Hydroelectric Power Corporation and the GOI's electricity plans where capacity additions of 5159 MW have been identified for the 8th Plan.

Presently, the share of gas-fired generation capacity is only 2.7 percent, concentrated largely in the North-eastern and Western regions where domestic natural gas is produced. The potential for gas-fired generation, however, could be higher. For instance, it is estimated that over 4 billion m^3 of natural gas is being flared in the Bombay high basin annually and that this gas could generate about 12,000 GWh of electricity. As part of its 8th Plan, the GOI wants capacity additions in the order of 6800 MW from natural gas-fired generation. Questions, however, remain as to whether this flared gas can be delivered economically to utilities and how much of the incremental gas supplies the government would allocate to the electricity sector over other competing gas-consuming sectors such as fertilizers, petrochemicals, and transportation.

Nuclear power has suffered several setbacks. As of 1991/92, 2035 MW of nuclear capacity was installed in the Northern, Western and Southern regions, accounting for only 2.9 percent of India's total installed capacity. Seven more 235 MW units are under construction, and the Department of Atomic Energy plans to install 5000 MW of nuclear capacity by the turn of the century. This targeted capacity, however, may not be achievable in light of the various technical and financial constraints that have plagued India's nuclear power program to date. Safety, long-term waste management and the eventual decommissioning of plants continue to be areas of concern both to the Indian electricity sector as well as international funding institutions.

1 3 3 Generation

In line with additions to installed capacity, total generation by public utilities increased rapidly, from 5106 GWh in 1950 to 264,231 GWh in 1990/91, registering an annual growth rate of 10.4 percent over this pėriod (see Table 1.2; regional characteristics are given in Table A 3 in Appendix A). Until the 1980s, the growth rate in hydro and thermal generation was comparable, but during the 1980s, hydro generation increased at a rate of only 4.4 percent compared to a growth rate of 11.6 percent in thermal generation. Owing to the decline in hydro development and prevailing peak power deficits. coal-fired

thermal power units are often used for meeting peak loads.[10] Nuclear power plants accounted for 2.5-2.7% of total utility generation.

Table 1.2

Annual Rate of Growth of Total Generation
(percent)

Period	Thermal	Hydro	Total
1950/51 - 1960/61	13.4	12.0	12.7
1960/61 - 1970/71	12.9	12.4	12.7
1970/71 - 1980/81	7.7	6.3	7.2
1980/81 - 1990/91	11.6	4.4	9.1
1950/51 - 1990/91	11.4	8.7	10.4

SOURCE: Centre of Monitoring Indian Economy, 1991.

1.3.4 Performance of Thermal Generating Capacity

The poor performance of India's existing generating units has been a principal cause of power shortages and unreliable quality of power supply. The primary culprits are the coal-fired thermal power stations which account for over 65 percent of total installed capacity. As shown in Table 1.3, the average plant load factor (PLF) of thermal power stations in India is less than 60 percent, but varies considerably across regions. In 1989/90, the Southern region had the highest PLF of 65.6 percent, while the Eastern and the North-eastern regions recorded very low PLFs of 38.5 percent and 26.8 percent, respectively. In contrast, hydropower stations have far better track records due to the fact that their performance relies largely on water flow.

However, not all of the thermal generating stations have such dismal records. For instance, the performance of 500 MW and 200 MW units has been satisfactory, and their PLFs have been higher than the national average. It is, in fact, the thermal units of 120/140 MW and below that are cause for concern.[11] Most of these units have already logged more than 100,000 running hours and their performance can only be improved through a long-term rehabilitation or repowering program.

Table 1.3

Performance of Thermal Power Stations
During 1990/91
(percent)

Region	PLF	Planned Maintenance	Forced Outages	Plant Availability
Northern	55.28	9.22	18.50	72.28
Western	57.69	12.47	11.33	76.20
Southern	61.69	8.57	17.31	74.12
Eastern	36.51	16.84	23.89	59.27
North-eastern	24.62	25.68	28.26	46.06
All India	53.89	11.81	16.49	71.70

SOURCE: Central Electricity Authority, 1990/91.

Performance also varies between the private sector, central sector and the state sector. For example, in 1990-91, while thermal stations operated by private utilities and the central sector (NTPC and NHPC) utilities achieved an average PLF of 58 percent, the corresponding figure for SEBs was 51 percent (see Table 1.4). Part of the explanation relates to the fact that centrally-owned power stations are larger (200/500 MW) and are relatively new. On the other hand, the SEBs have a large number of small generating units, many of which are old and worn out.

In undertaking the retrofits required to improve the PLF, the SEBs are in a catch-22 situation. They are generally reluctant to undertake plant renovation and modernization because it involves extended shut-down of the plant, in the face of continued pressure to meet growing power demands. In addition, most of the SEBs do not have the financial resources to fund renovations and modernization schemes (see Section 1.4).

Table 1.4

Plant Load Factor of Thermal Power Stations
By Sector
(percent)

Sector	1983-84	1985-86	1989-90	1990-91
Central	54.8	61.9	62.2	58.1
Private	64.1	57.5	69.5	58.4
State	44.9	49.2	53.0	51.3
Total	47.9	52.4	56.2	53.8

SOURCE Central Electricity Authority, Performance Review of Thermal Power Stations 1990-91, New Delhi.

Due to the unwillingness or inability to undertake these refurbishments, high forced outage rates have occurred. During 1989/90, the all-India forced outage rate of thermal power plants averaged 15.3 percent due to 7313 outages resulting in availability levels of only 73 percent. In the North-

eastern regions, forced outages were as high as 51 percent resulting in only 44.7 percent plant availability[12] (see Table 1.5). Problems with boilers have consistently been the leading cause of these forced power outages.

Table 1.5

Percentage of Total Forced Outage Losses

Cause of Outage	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91
Boiler	38.05	31.61	33.70	39.29	35.46	31.65
Turbine	11.50	26.00	23.12	23.53	14.70	13.80
Generator	23.72	20.00	18.19	10.76	21.29	18.37
Other	26.73	22.39	24.99	26.42	28.55	36.18

SOURCE: Central Electricity Authority, Performance Review of Thermal Power Stations 1990-91, New Delhi.

Another factor contributing to poor power plant performance is the deterioration in the quality of coal delivered to thermal power stations. The average calorific value of steam grade coal received at power stations was about 4600 kcal/kg in 1975/76 falling to 3800-4100 kcal/kg since 1985/86.[13] An analysis of 229 collieries in 1989/90 revealed that only 82 collieries could--at times--supply the declared grade of coal, and the remaining 147 collieries have never supplied their declared grade to the power stations.[14]

Poor quality coal means that for each unit of electricity generated, more coal is consumed, and consequently, higher emissions and more problems with ash disposal result than would be the case with a higher grade coal. Coal consumption now ranges between 0.70-0.72 kg/kWh rather than the CEA norm of 0.60 kg/kWh.[15]

Poor quality coal also drives up the need for fuel oil as larger amounts of oil are needed in the boiler to maintain reasonable operation. During 1989/90, fuel oil consumption in the central sector and private utilities was 5.7 milliliters (ml) per kWh and 6.8 ml/kWh respectively, while state-owned power stations consumed 11.3 ml/kWh, (see Table 1.6). While 500 MW and 200/210 MW generating units recorded 4.4 ml/kWh and 7.1 ml/kWh of specific oil consumption, smaller units (140/150, 120, 100/110, 60 MW) used between 13-20 ml/kWh.

Table 1.6

Secondary Fuel Oil Consumption
By Sector
(ml/kWh)

Sector	1985/86	1986/87	1987/88	1988/89	1989/90	1990/91
Central	9.0	6.4	7.6	6.4	5.7	4.89
State	16.0	14.3	11.6	11.8	11.3	9.24
Private	9.3	4.7	4.6	8.1	6.8	8.95
All India	13.9	12.0	10.5	10.0	9.2	7.69

SOURCE: Central Electricity Authority, Performance Review of Thermal Power Stations 1990-91, New Delhi.

In an attempt to improve the generating efficiency of thermal power stations, the Central Electricity Authority launched a renovation and modernization program in September 1984. The program covered renovation and modernization of thermal generating units having ratings of 140 MW and lower and also certain 200/210 MW units whose performance had been unsatisfactory. The Phase I program covered 34 thermal power stations with a total capacity of 13,475 MW. The objective was to improve the average PLF from 46 percent to 53 percent and thereby generate an additional 7000 GWh per year. The program resulted in overall increases of 11,000 GWh, 10,800 GWh and 10,700 GWh during 1988/89, 1989/90 and 1990/91, respectively.

The success of Phase I propagated a second phase of the program with targets to improve the PLF from 53 percent to 58 percent, effectively adding thermal capacity of 1600 MW. This portion of the program also targets hydro facilities. Forty-nine hydro plants have been identified for upgrading and renovation.

1.3.5 Transmission and Distribution (T & D)

India's T & D system comprises a 400 kV network as the main and bulk transmission system in each region; a 220 kV, 132 kV and 110 kV network as the main and support transmission systems in each state; a 66 kV, 33 kV and 22 kV network as sub-transmission systems; an 11 kV network as primary distribution systems; and a 400 V (three-phase) and 230 V network as local distribution systems.[16]

While the predominant technology for electricity distribution and transmission has been Alternating Current (AC) technology, High Voltage Direct Current (HVDC) technology is being introduced for back-to-back interconnection between the Northern and Western regional systems and also for the bulk transfer of power in the Northern region. Currently, one HVDC line has been built between Singrauli and Dadri in the Northern region for bulk transfer of power to the Delhi area from the Singrauli area in central India where there is a concentration of pit-head, super-thermal power stations.

Even though the T & D network expanded by about 6.3 percent per annum during the 1980s, its growth has not kept pace with the capacity to supply power. As a result, the generation levels of certain power stations (for example, Singrauli and Rihand Thermal Power Stations in the Northern region) had to be curtailed because not all the required 400 kV lines could be commissioned in time to deliver the power generated.

Adding to an already over-burdened T & D system, T & D losses merit concern. T & D losses for Indian utilities in aggregate increased from 17.5 percent in 1970/71 to 21.7 percent in 1985/86, and then levelled off to about 21 percent by 1990/91. As a result, for every GWh of electricity demand about 1.265 GWhs must be generated.

The high T & D losses stem from:

(i) the GOI who assigns a low priority to T & D in relation to building generation capacity;

(ii) the urgency to provide electricity for rural populations that results in long lines and low power factor without strengthening the back-up transmission and sub-transmission system;

(iii) an over-abundance of transformation stages causing high transformer losses;

(iv) an inadequate reactive compensation in the system; and

(v) an improper load distribution resulting in system overloading.

Apart from technical losses, the incidence of non-technical losses is also quite high. According to a study conducted by TERI for the Delhi Electricity Supply Undertaking, total T & D losses of 22 percent comprise about 13 percent technical losses and 9 percent commercial losses.[17] The reasons for high non-technical losses include electricity theft, faulty meters and un-metered supply. If non-technical losses could be curtailed, T & D operating losses in India would closely match those of most developed countries.

Reducing non-technical losses requires a judicious mix of legislative support, increased customer awareness, improved billing and collection procedures, and reliable and high quality meters. Attention to technical losses includes such measures as augmenting the network, installation of capacitors, reconductoring, and eliminating both underloading and overloading of distribution transformers. In the end, reductions in T & D losses would mean more electricity delivered per unit kWh generated which would reduce the impact on the environment and lower the cost of electricity delivered.

1.3.6 Electricity Consumption

Electricity consumption in India has grown at an annual compound rate of 9 percent per year during the last four decades and is far outstripping supply capabilities.

This growth in consumption is not uniform across sectors (Table 1.7) The growth rate of electricity consumption in the agriculture sector is the most notable. The advent of such growth came about after the severe drought of 1965-67, when the government began a large program for installing electric pumpsets for irrigation. Since then electricity consumption in the agriculture sector has increased at a compound annual growth rate of 13.6 percent. In some states, like Punjab, Haryana, Uttar Pradesh and Andhra Pradesh, 35 to 40 percent of total electricity consumption is for irrigation purposes.

Table 1.7

Sectoral Electricity Consumption
(percent)

Year	Domestic	Commercial	Industry	Agriculture	Others
1950/51	12 4	6.9	63.8	4.2	12.8
1960/61	10.7	6.1	69.4	6.0	7.8
1965/66	8.8	6.2	70.6	7.1	7.3
1970/71	8.8	5.9	67.6	10.2	7.5
1975/76	9.7	5.8	62.4	14.5	7.6
1980/81	11.2	5.7	58.4	17.6	7.1
1985/86	14 0	5.9	54.5	19.1	6.5
1989/90	16.1	5.8	46.3	25.0	6.6
1990/91	16 8	5.9	44.2	26.4	6.7
1991/92	17 3	5.8	42.0	28.2	6.7

SOURCE· Public Electricity Supply, All India Statistics, General Review, 1991-92, Central Electricity Authority, New Delhi.

After agriculture, the domestic market has contributed most to the growth of electricity consumption. Since 1965/66, it has almost doubled its percent share of total consumption The commercial sector captures about 6 percent of total electricity sales Industry, while still accounting for the highest percentage share of total electricity consumption, has dropped markedly from a peak of 70 6 percent in 1965/66 to 46 3 percent in 1989/90.

Electricity is now also being used in the transportation sector, particularly for railways Electricity consumption in railways, though accounting for only 2 3 percent of the total electricity consumption, has increased from 372 GWh in 1970/71 to 5338 GWh in 1989/90--an annual growth of 15 percent

1.3.7 Rural Electrification

Important to the rapid increase of agricultural demand is the Rural Electrification Program (REP) which was introduced in the First Plan (April 1, 1951 - March 31, 1956). While it was originally designed to provide electricity as a social amenity to rural areas and confined to only a few states, this program was expanded to cover all states. The REP gained special importance after the severe drought in the mid-sixties when the program enhanced access to electricity for rural areas for operating irrigation pumpsets to use available groundwater. It was further strengthened by the formation of the Rural Electrification Corporation (REC) in 1969 which now provides over 90 percent of the funds for rural electrification as concessional loans to the State Electricity Boards. As a result of these efforts, 84 percent of Indian villages have been electrified and nearly 9 million pumpsets energized (see Table A.5 in Appendix A). Apart from the pumpset energization, emphasis has also been placed on promotion of industrial load in villages by extending electricity connections for setting up low tension (voltage) industries.

While the REP has been impressive in terms of the number of villages electrified, "electrification" of a village means that one or more households in the village have electricity. Thus, while 84 percent of Indian villages have been electrified, only 27 percent of rural households actually have access to electricity.

Furthermore the rather impressive statistic of "84 percent of villages electrified" must not overshadow the severe drawbacks to this program. The most notable is the heavy financial losses incurred by the State Electricity Boards (SEBs) in providing electricity at low rates for this program which is resulting in wasteful use of electricity and underground water. In addition, the program has resulted in an increase in T & D losses, as the higher priority the GOI places on building generation capacity combined with a lack of funds has meant that the extensions to the T & D network were sub-optimal.

1.3.8 Financial Performance of SEBs

The financial condition of the SEBs is alarming. Even though the Electricity Supply Act of 1980 stipulates that SEBs are to carry out their operations and adjust their tariffs so as to earn a net return of 3 percent on net assets at the beginning of the financial year, all but one or two of the SEBs have a negative rate of return. The rate of return of all SEBs has declined from -10.5 percent in 1985/86 to -14.2 percent in 1991/92.[18]

The poor financial condition of the SEBs not only creates formidable problems for their future development but also presents difficulties in meeting day-to-day expenses. Often the utilities do not have money to buy spare parts and to carry out renovation and modernization of their plants, resulting in poor operational efficiencies. Furthermore, the lack of resources

means that little attention is paid to emission control measures, such as installation of electrostatic precipitators (ESPs) for controlling particulate emissions, water treatment prior to discharge of boiler blowdown into the surrounding water bodies, etc.

The underlying causes for the decaying financial performance find their genesis in pricing policies directed at poverty alleviation and economic development, the Rural Electrification Program, and state controls over finances.

SEBs incur substantial losses in their provision of electricity to rural and remote areas at subsidized rates under the auspices of the REP. While the losses incurred from subsidized rates for rural and remote customers are supposed to be compensated for by the State Governments, they are not being fully reimbursed. Under the current dispensation scheme, state governments limit the SEB claims to the lesser of: the loss or the shortfall in revenue required to achieve the prescribed rate of return. In effect, this has meant that SEBs are only able to claim 50-60 percent of the losses with the remainder to be absorbed by the SEBs.[19] In addition, there are substantial delays on the part of the State governments in providing these monies to the SEBs. As of March 31, 1990, outstanding subsidy payments were estimated at Rs. 62,990 million. Non-payment or partial payment after substantial delays seriously affects the financial viability of the SEBs since they have to resort to heavy market borrowing to meet the shortage of funds, borrowing that is already placing them in financial jeopardy.

The disclosed financial state of the majority of SEBs can best be described as perilous by North American standards. The situation may, in fact, be even worse as the accounting practices currently in place ignore items such as accumulated losses which would further downgrade their financial position.

The SEBs are highly leveraged entities (i.e., high debt to equity ratio). SEBs generally have a debt to equity ratio ranging from 10:1 to 20:1, compared to Canadian publicly-owned utilities with debt-equity ratios that are in the comfortable order of 4:1. The State governments (which are <u>the</u> shareholders) provide no equity for the SEBs, although recently a few governments have converted a portion of the SEBs' loans to equity. The only equity available is in reserves, surplus and consumers' contribution towards capital assets, and grants and subventions from the government toward capital assets.

The high debt to equity ratio for already unprofitable companies places them in a precarious position, as significant cash flows are needed to meet their debt servicing requirements. Unfortunately, the SEBs are not in the position of having high cash flows as the interest charges on borrowings alone are more than the operating profit (i.e., profit before interest and depreciation).[20]

Usually, when a company does not have the cash flow to meet their debt requirements and debt matures, lenders may not renew the debt and/or will require significantly higher rates of return for further financing. In the case of the SEBs, most borrowings from financial institutions are guaranteed by the State governments, and consequently, the SEBs have not defaulted on repayments of their loans.

The repayment schemes, however, are such that the SEBs must pay back the monies before capital expenditures. For instance, the repayment of the loans to financial institutions come out of capital receipts from State governments' future institutional and market loans. The government then adjusts the interest due to them from the SEBs from the subsidy payable and the plan allocation of the SEBs. This subsidy is for the losses suffered by the SEBs on account of concessional supply of electricity. Since the SEBs cannot defer these current expenditures, they curtail capital expenditures. As such, SEBs trade-off long term capital expenditures to repay the State Government, thereby delaying projects and causing cost overruns.

1.3.8.1 Tariffs

Electricity tariffs do not generate enough revenue to cover SEB costs. While the Electricity Supply Act stipulates that pricing is the purview of the SEB and that State Governments are only to provide an advisory role, State Governments often directly influence electricity rates. As a consequence, prices are usually set in accordance with socio-political interests rather than economic ones.

The guardianship of the agricultural sector is reflected in the prices for this sector. Electricity prices are lowest for the agriculture sector, and over the years, the gap between the average cost of supplying electricity and the average revenue received from the agriculture sector has been widening (see Table 1.8). An analysis of 22 utilities shows that electricity tariffs for agriculture consumers declined in 5 utilities and remained unchanged in 13 utilities during the period 1985/86 to 1990/91.[21] One of the reasons for the decline in the average agriculture tariff since the mid-1970s is the gradual change over from metered supply to 'flat-rate' tariff based on the connected load (the horsepower of pumpsets), primarily due to administrative conveniences and reduced cost of billing and collection. This, however, has encouraged misuse and waste of electricity. There are, for example, several instances of farmers running small industries on agricultural connection. Consequently, all-India losses incurred as a direct result of supplying the agricultural sector increased from Rs 12 billion in 1985/86 to Rs 38 billion in 1990/91.[22]

Table 1.8

Comparison of Average Cost of Generation, Average Revenue Realized from Agriculture, and Overall Average Revenue Realized
(paise/kWh)

Year	Average Cost of Generation and Supply	Average Revenue Realized	
		Agriculture	Overall
1975/76	24.01	21.15	18.39
1980/81	41.90	18.84	33.23
1985/86	74.84	18.15	55.00
1989/90	101.50	15.30	71.60
1990/91	104.80	n.a.	80.90

SOURCES. (1) GOI, 1990; and (2) Annual Report, CEA, 1989/90.

Like agricultural customers, domestic customers are also protected from paying the full cost of providing electricity to them as part of the GOI's plan to help alleviate poverty. The average tariff for the domestic sector still falls below the average cost to supply electricity in all the SEBs. In 1991/92, the estimated all-India losses from subsidized electricity sales to the domestic sector totalled Rs 12 billion. One important change in pricing has been the shift from average energy rate (paise/kWh) and decreasing block rates[23] of the 1950s and 1960s to promote electricity consumption, to increasing block tariffs[24] designed to curb the rate of growth of electricity consumption.

In order to partially make up for the losses that the SEBs incur from subsidizing agriculture and domestic consumers, industrial and commercial consumers are often charged a higher rate than the average cost of supply to them In spite of cross subsidization by the industrial and commercial sectors, unit average revenue is still less than the average costs of supply in nearly all the SEBs, and the gap has increased over time. For all of India, per unit revenue losses have increased almost six-fold, from 4.13 paise in 1974/75 to 8.67 paise in 1980/81 and to 23.9 paise in 1990/91.

Consequently, all-India commercial losses of SEBs in 1991/92 were Rs 45 billion and the losses for 1992/93 are estimated at Rs 51 billion.

1.4 Summary and Prospects

The principal observation stemming from this review of the situation in India's electric power sector is the disparity between the growth in electricity demand and the capabilities to meet that demand. This disparity is rooted in the economic and social control by state and central governments, a deficient power supply, poorly performing plants, inadequate T & D networks, subsidized electricity prices for agricultural and domestic customers, cash-starved SEBs, and an overwhelming population.

To remain true to the search for Indian solutions while borrowing successful strategies from North American utilities, it is important to highlight those delimiting factors pertinent to India's electricity sector, namely that:

- In spite of recent policy reforms, over 90 percent of the electric sector will continue to be largely managed by state and central governments.

- Coal will continue to be an important fuel source in India. In choosing this option, the electric power sector will either have to finance railway expansions to move the coal to the power plants or re-locate the power plants next to the pithead with corresponding expansions to the T & D network. In addition, attention will have to be paid to the impact on the people in the vicinity and the environmental impacts of concentrating many coal-fired power plants in one area.

- The reliance on coal has caused some trepidation given recent and severe peaking shortages, and has prompted a re-consideration of the viability of hydro power. The problem, however, is that large hydro projects are facing considerable controversy by both international environmental groups and financial institutions, technical problems, and geographical limitations. While mini-hydro facilities offer some option, they alone cannot satisfy the existing and growing electricity needs in India and will, therefore, have to be augmented with other generation facilities.

- The prospects for natural gas-fired generation do not look promising--unless there is a change in both policy and economic circumstances. At this time, the government allocates what limited gas supplies there are to fertilizers, petrochemicals, and the power sector, which are the major gas demand sectors in the economy.

- While the GOI continues to plan additions to nuclear capacity, expectations are that technical and financial problems combined with disposal and decommissioning will limit many if not all additions. International lenders concerned with nuclear disasters and use of nuclear products for missiles are reluctant to provide funding for nuclear power. Thus, if India wants more nuclear capacity it will likely have to be self-funded.

- The existing T & D system is not matching the generation capabilities of the system and losses are high relative to North American standards. Expansion of the T & D network in tandem with new generation additions is required. This could be augmented with strengthening of the existing T & D network by installation of capacitors, reconductoring, elimination of both underloading and overloading of distribution transformers, etc. Reducing non-technical losses is also needed and requires a mix of legislative support, increased customer awareness, improved billing and collection procedures, and reliable meters.

Like utilities all over the world, Indian utilities are being pressured by environmental groups to produce power in an environmentally responsible manner.

While India's situation has elements that are distinctly theirs, there are some parallels to the challenges that utilities outside of India are facing Utilities in North America, for instance, have faced relentless opposition by environmental groups to virtually any form of electricity generation, although the opposition has been less vocal to 'the clean fuel of choice,' natural gas. For instance, it is conceivable now that no utility in Canada will be able to build another large-scale hydro facility. Nuclear power has been riddled with operating difficulties and unresolved challenges associated with plant decommissioning and waste disposal. The concern with nuclear power has prompted the Ontario Government to impose a moratorium on nuclear power expansions.

Coal-fired generation has been spared somewhat largely because of advancements in clean-coal technologies which can dramatically reduce emissions and significantly increase technical efficiencies. These coal combustion technologies include integrated gasification combined cycle, atmospheric fluidized bed combustion, and pressurized fluidized bed combustion

On the whole, large-scale electricity production is also no longer enjoying the economies of scale it once had, and many utilities are suffering shrinking financial resources in light of economic recession. These factors, combined with the pressure from environmental groups, have caused a change in philosophy in the electric power sector.

Electric utilities now, rather than building large-scale power facilities, are considering ways to augment their existing generation system through such options as purchasing power from small independent power producers and developing co-generation for industrial markets, where heat and electricity are joint products of the system. The increasing costs of T & D systems relative to smaller modular technologies such as photovoltaics, has propagated interest in the possibilities for dispersed electricity generation, where power is produced 'on-site' or within communities and transmitted locally Dispersed electricity generation offers not only a reduction in T & D needs, it also lowers capacity requirements. Utilities have also branched into *demand-side management*, where the utility designs programs to encourage customers to alter or reduce their energy and peak demands, as a way to defer capacity needs.

Because many of the technologies used for cogeneration, small independent power production, and dispersed electricity generation produce lower levels of emissions, and because demand-side management reduces the

need for capacity expansions, these activities have generally met with approval by environmental groups.

The situation facing the SEB's in India is somewhat analogous to that facing the North American utilities in the early 1980s. Hence, the options North American utilities have explored over the last several decades present opportunities in India as well.

1.5 Project Overview

This study will focus on the opportunities to balance India's electricity supply and demand considering the costs and environmental impacts of both conventional and novel approaches. The study includes the following modules:

(i) evaluate new coal combustion technologies, such as integrated gasification combined cycle, atmospheric fluidized bed combustion, pressurized fluidized bed combustion, that combine efficiency and reduced emissions for capacity expansions;

(ii) examine the ability of cogeneration in the industrial sector to augment the electrical system;

(iii) investigate the potential for interregional electricity trade to augment capacity;

(iv) examine decentralized electricity systems, such as wind, biomass, and mini-hydro to meet demand for rural and local populations and reduce T & D needs; and

(v) evaluate demand-side management, conservation and load reduction initiatives for all sectors and how this demand can in turn reduce capacity needs.

The costs of these options will be compared to existing electricity generation options, such as coal, hydro, nuclear, and natural gas and the associated T & D requirements. In all cases, the aggregate emissions of SO_X, NO_X, and CO_2 will be calculated.

The MARKAL/ELGEM model has been selected to aid in the analysis of these options. The MARKAL/ELGEM model is a linear programming electricity generation model which has been developed for analysis of long-term electric power issues in Canada by the Canadian Energy Research Institute and the Alberta Research Council. It can be used to determine the most cost-effective, environmentally-compatible electric power generation mix given a variety of constraints and system options. The fuel and technology performance characteristics embodied in the Canadian version of the model will be modified to reflect the situation in India. The model design includes the capability to disaggregate into market regions.

Given the demand forecast for each region and the costs of all perceived electricity generation and transmission options, the model provides the:

- optimal power generating additions schedule in each region over time, by technology;
- optimal construction schedule for new interregional transmission lines;
- load mix in each region over time, by technology; and
- interregional transfers of power.

The experience of Canadian utilities and electric equipment manufacturers in dealing with the considerable technical challenges of electric power system management in Canada has potential for application to India. These opportunities for Canada-India linkages will be identified and explored in a companion report to this study.

Endnotes

[1]Unless otherwise stated, much of the technical information in this section comes from Progress Report No. 2, Environmentally Sound Energy Development - India Pilot Project, submitted to the United Nations Environmental Programme (UNEP) by TERI, January 1993. Updates and evaluation of the policies and electric power data is a joint effort of TERI and CERI.

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[5]New Delhi Correspondent, "Harvesting India's Reforms, *Economist*, March 6, 1993.

[6]Tata Energy Research Institute, *Environmental Considerations in Energy Development: India Country Study*, report prepared for the Asian Development Bank (New Delhi, India, July 1992).

[7]K. Sridhar and A. Terway, "Coal Use for Power Generation in India--Needs and Options," in the *International Conference on Coal, the Environment and Development: Technologies to Reduce Greenhouse Gas Emissions* (Paris, France: IEA, 1991).

[8]Thermal power stations under various capacity groups can be found in Table A.2 in Appendix A.

[9]Tata Energy Research Institute, *UNEP Greenhouse Gas Abatement Costing Studies: India Country Study, Phase 1* (New Delhi, India: April, 1992).

[10]Because the start-up time for a coal-fired thermal power unit is four to five hours, these units have to continue generating at partial load conditions which reduces their overall efficiency.

[11]The performance of thermal power stations in various capacity groups can be found in Table A.6 in Appendix A.

[12]Central Electricity Authority, 1989/90.

[13]Central Electricity Authority, 1989/90.

[14]Central Electricity Authority, Performance Review of Thermal Power Stations, 1989/90.

[15]Details of coal quality and coal consumption for various thermal power stations are given in Table A.7 in Appendix A.

[16]Table A.4 in Appendix A presents data on the total circuit-kilometres of T & D lines, as of March 31, 1980 and 1989 by region.

[17]Kapil Thukral, Sengupta D.P., Sharma P.D., Debapriya Das, Laxmi Prasanna P.V., Sabharwal S., "Measurement and estimation of

transmission and distribution losses in the DESU system", report submitted to DESU, February 1991.

[18]The financial performance of the SEBs is depicted in Table A.9 in Appendix A.

[19]See Table A.12 in Appendix A.

[20]The key financial indicators are assembled in Table A.13 in Appendix A.

[21]Growth rates for electricity tariffs during the period 1984/85 to 1989/90 are illustrated in Table A.9 in Appendix A.

[22]The losses due to supplying electricity to the agricultural sector is presented in Table A.10 in Appendix A.

[23]Where tariffs decrease as consumption increases.

[24]Where tariffs are positively correlated with consumption.

Chapter 2

DECENTRALIZED GENERATION

2.1 Introduction

In centralized electricity generation, a utility generates electricity from a centrally located power plant and then transmits and distributes electricity to end-users, normally located along an electricity grid. With *decentralized (dispersed) electricity generation*, the electrical power source is located at or near the premises of the final electricity user(s); electricity can also be distributed locally, either within communities or between companies.

For developed countries, on-grid electrical generation has tended to service all energy needs: water heating, building temperature, cooking, pumping, etc. With dispersed electricity generation, this may be done by combining various 'alternative' technologies and design strategies. For example, basic electrical needs such as communication and lighting can be met using a wind turbine system; the heating and cooling of a building can be done using alternative building design; and water heating could be done with a solar water heater.

Shifting to customer-based generation offers several advantages to the utility. For instance:

- the utility can defer transmission and distribution requirements;
- in mature electricity markets, utilities can expand their business opportunities;
- utilities can provide power relatively quickly, in some cases in a matter of weeks or a few months with dispersed electricity generation options;
- smaller generation options diversify risk for utilities;
- utilities are better able to match demand and supply with these technologies;
- the smaller technologies can present more aesthetically acceptable alternatives to large-scale facilities; and
- dispersed electricity generation offers fuel diversity for the utility.

The electricity user has the potential to gain:

- a potentially cheaper and more reliable alternative to purchased electricity from the central utility, especially in remote areas off the grid;

- a more environmentally friendly option to centralized generating facilities such as coal-fired power plants;
- flexibility in sizing--some dispersed generation technologies can be sized almost exactly to the customer's needs and as needs change, modules can be added; and
- incremental revenue, if the power generated is greater than the user's needs and excess power can be sold to neighbouring facilities.

These reasons alongside (i) considerable improvements in reliability, costs, and efficiencies of these technologies; (ii) increasing costs of large-scale electricity generation in relation to 'small-scale' demand increases; and (iii) favourable public policy, have resulted in active consideration of dispersed electricity generation in North America.

Definitive conclusions cannot be made about which technology is the 'best' as the suitability of these technologies is **site specific** and dependent on resource availability, technology availability, operation and maintenance (O&M) infrastructure, technology costs, user needs and tastes, the cost of acquiring the electricity from the utility serving the area, and environmental considerations. In sum, there is no one technology that can meet the requirements in every situation. In fact, it is when these systems are combined, for example, wind-diesel, wind-solar, or photovoltaics-passive solar buildings, that they can more closely fulfill energy needs. As such, systems should be custom-designed for the customer.

Some of the more distinguishing attributes of the various technologies include:

(i) wind and solar power are intermittent resources.

(ii) wind can be directly cost competitive even with traditional large-scale utility generation.

(iii) photovoltaics are the predominant solar energy technology

(iv) photovoltaics are not cost effective for the full range of electrical needs, but are cost competitive in many niche applications, particularly remote sites and, in some cases, for peak power.

(v) photovoltaics are modular and can be designed for the smallest application, like powering a hand-held calculator, to large-scale (MW) systems.

(vi) the comparatively lower bulk density and energy density associated with biomass options means that large input volumes are required; if the biomass has to be transported long distances, the heat value of this resource can be dramatically reduced.

(vii) biomass, like wind, can be cost competitive even against large-scale utility generation.

In drawing these conclusions, it is important to point out that unlike biomass, which has a long history of commercial application world-wide, the favourable technical merit and economics of wind and solar are rather recent developments.

2.1.1 Decentralized Energy Systems in India

As in many developing countries a large proportion of the Indian population still depends on traditional sources of energy. However, these are being increasingly substituted by more efficient commercial fuels. The country has moved from being largely a biomass based economy at the time of independence to one that is 60 percent based on commercial energy forms. The rural sector, however, remains predominantly dependent on biomass fuels.

The development of conventional commercial energy systems has had manifold adverse environmental impacts. Coal mining has led to degradation and loss of agricultural land and forest. Coal-fired thermal power plants cause air pollution through harmful emissions. Environmental problems are also associated with hydrocarbon exploration, production, transportation and refining.

In this context, the role that renewable energy technologies (RETs) can play for sustainable energy use is receiving increasing attention. Major elements of the Future National Energy Strategy (FNES) articulated in the 8th Five Year Plan document, explicitly address these concerns and point to RETs as feasible alternatives.

The arguments for deploying RETs in defined situations in preference to conventional alternatives include the following.

Sustainable use:

RETs are sustainable as they depend on natural energy flows that are non-depleting (e.g., solar, wind, hydro, geothermal). The sustainability of RETs also derives from the fact that in general they are environmentally benign as compared to their conventional commercial energy counterparts. Solar, wind, and micro/mini-hydro based RETs have no polluting emissions and generate no wastes.

Reducing system losses:

Conventional energy technologies often go through multiple conversions. For example, the chemical energy in coal is converted to heat, which is in turn converted to electricity in a power plant. This electricity itself undergoes various voltage (and perhaps AC-DC-AC) transformations, before it

is supplied to the user. The transmission over a grid involves loss of electrical energy to heat dissipated in transformers and power lines. The user often converts electricity back to heat (i.e., in cooking, water heating, absorption refrigeration). These multiple transformations involve energy loss at each stage, with the result that the final energy service obtained is a fraction of the original primary energy used. On the other hand, several RETs involve either a single stage of conversion (e.g., biogas generation, photovoltaic), or simply a stage of concentration (e.g., solar cookers, water heaters). The energy supply from these RETs can be directly matched to end-use. Thus, system losses can be substantially reduced, thereby improving the economics for renewables.

Decentralized applications:

Several RETs are well suited to decentralized applications (as opposed to centralized grid supply) because of the flexibility in scale that they offer. Two important implications follow: first, since the number of devices that would be involved in countrywide use is extremely large, economies of scale in manufacture may be realized. Second, decentralized systems are easier to maintain than large centralized ones. Technologies like biogas can be promoted at the village or cluster-of-villages level and effectively managed locally.

Decentralized RET systems may also prove more reliable than conventional centralized systems. In a centralized energy system, since different parts are interconnected, a failure in one part may entail failures over other parts, or over the entire system. For example, the failure of a major peak load generator may involve load-shedding over an entire electricity grid. In the case of decentralized RETs, a failure or interruption in the RET system itself does not affect a large number of users. For example, failure of a PV power plant in a remote village will only have an impact on those directly benefitting from its use in that area.

Even in an economic sense, decentralized systems offer certain advantages over centralized ones The setting up of a large, centralized energy system involves not only the capital and O&M costs of the system, but the costs of physical, organizational and regulatory structures, such as technical and management personnel. Additionally, centralized systems take considerable time to plan, implement, and commission Compared to this, decentralized RET systems require little or no additional infrastructure, and their technical maintenance requirements are on a much smaller scale than centralized systems. Thus, the absence of large-scale organization and additional infrastructure, reduced regulatory effort, much shorter gestation, and reduced likelihood of unforeseen delays in execution, confer significant economic advantage to decentralized RETs in comparison to centralized, large-scale energy systems

2.2 Renewable Energy Projects in Canada

Canada has a rather limited record of renewable energy development which makes sense given that the technologies have not compared favourably to other forms of electrical generation on an economic basis until recently (with the exception of hydro facilities and, to a lesser extent, biomass). Large-scale hydro continues to dominate electrical generation in Canada, accounting for 57 percent of Canada's installed electrical capacity.[1]

Biomass, one of two components (the other component being waste gases) of the "other" electrical generation category, only amounts to approximately two percent of the recorded[2] installed electrical capacity in Canada.[3] Wind and solar resources are 'too small to meter' in statistical publications collecting aggregate data on the electricity sector.

Signs of more rapid development of renewable energy technologies are appearing in Canada. The federal government and some provincial governments have either instituted policies or are reviewing options to encourage renewable energy projects. A number of utilities are analyzing the cost effectiveness of installing dispersed electricity generation systems for their remote customers rather than continuing to extend the transmission network. Cases in point include B.C. Hydro, TransAlta Utilities, Ontario Hydro, Hydro Québec, and Newfoundland Light & Power Company Field testing is also being undertaken by non-utility organizations and companies.

2.2.1 Wind Energy

Canada's installed wind generation capacity is about 7.5 MW--substantially less than either that of California or Denmark.[4] Moreover, the potential for remote power systems is significantly smaller than that of developing countries due to the judicious efforts of Canadian utilities to provide reliable access to all people.[5] There remains, however, several promising sites--especially in northern communities where there is strong reliance on expensive diesel generation.[6] In Canada, the areas with potential include: Newfoundland and Labrador; the Iles de la Madeleine; mainland Québec; the Queen Charlotte Islands, the North West Territories; and to a lesser extent Ontario, Manitoba, the upper B.C. coast, and Saskatchewan [7]

Extensive field tests of wind turbines have been undertaken by two organizations in Canada: the Atlantic Wind Test Site and the Southwest Alberta Renewable Energy Test Site. Field tests have also been undertaken by both utilities and non-utility organizations.[8]

- Ontario Hydro (Fort Severn Wind Turbine Demonstration),
- Hydro Québec (Kuujjuaq wind-diesel project and EOLE),

- Newfoundland Light & Power Company (Bell Island Wind Farm),
- B.C. Telephone Company (the Calvert Island Power System),
- Health and Welfare Canada (Hall Beach Wind Energy Conservation Demonstration),
- Northern Canada Power Commission (Cambridge Bay Wind Conversion System Demonstration),
- Newfoundland Government and Natural Resources Canada (Four Mile Pond Radio Site),
- Natural Resources Canada (Observatoire du Témiscouata, Radio MF Charlevoix, Ghost Lake Windpump),
- Newfoundland Government (chlorination facilities in Newfoundland),
- the Town of Pincher Creek, Alberta (both privately-owned turbines and test sites), and
- Transport Canada (Coast Guard Light Station).[9]

The largest project is the 4 MW EOLE project in Québec.

There are nine large wind power suppliers and manufacturers in Canada.[10] However, it is the Danish that dominate the wind power industry.[11]

2.2.2 Solar Energy

Like wind turbines, photovoltaic systems are being tested at the Atlantic Wind Test Site and the Southwest Alberta Renewable Energy Test Site. Demonstration projects have also been undertaken by:[12]

- Natural Resources Canada (Tarryall Lodge, Kananaskis Park lighting system, Lenbrook Industries lighting system, Solarpac House in Mississauga, Grouse Mountain Atmospheric Environmental Services Site, stand-alone PV systems demonstration),
- B.C. Ministry of Agriculture and Fisheries (Cattle water pumping facility at Rattlesnake Hill),
- B.C. Telephone Company (Calvert Island Power System),
- Ontario Hydro (Big Trout Lake PV-diesel system),
- Lenbrook Industries/Orcalab (OrcaLab hydrophone network), and
- Rideau Valley Conservation Authority and TPK International (Baxter Interpretive Site - appliances for health and administrative centers)

The largest system is Ontario Hydro's Big Trout Lake Project. In Canada, there are ten manufacturers of active solar conversion devices and seven related companies (i.e., engineering services).[13]

2.2.3 Biomass

Biomass, other than wood used for heat and electrical generation by forest product companies, is not a widely used resource for electricity generation in North America. The earlier reliance on biomass fuels was replaced with the development of inexpensive and convenient fossil fuels.

Efforts to popularize biomass are moving cautiously in North America and for good reason. There are three factors that contribute to an uncertain future for biomass. First is the availability of efficient technologies for converting the biomass into other forms of energy such as liquid fuels and electricity. Conversion is important because these forms may require 50-90 percent less primary biomass than cooking directly.[14]

The second factor relates to the significant land use requirements and the potential for uncontrolled exploitation, leading to possibly disastrous effects on the ecosystem. For instance, exploitation of trees without replanting can lead to loss of biological diversity, soil erosion and desertification, siltation of rivers, and decreased agricultural productivity.[15]

The third factor relates to the transportation of the fuel. In fact, the dispersement of the fuel combined with the relatively low energy efficiencies has meant that plants are limited to a maximum size of 100-150 MW.[16]

As of 1989, there were 8,421 biomass generating plants in the U.S.[17] It is difficult to ascertain existing biomass facilities for Canada because reliable data for such facilities can only be obtained by the utilities, and unless these facilities are connected to the grid, which not all of them are, they do not have complete records.

Revitalization strategies currently in place are in the area of large-scale generation, deferring dispersed electricity generation options to the wind and photovoltaic energy sector. Much of the practical experience for small scale applications of biomass for fuels and electricity exist in developing countries such as India, Brazil, Kenya, and Zimbabwe.

2.2.4 Small Hydro

The areas with the greatest hydro generating capacities are in British Columbia, Québec, Ontario, Newfoundland, and Manitoba.[18] B.C. Hydro and Hydro Québec have plans for significant purchases from small-scale hydro facilities. B.C. Hydro had 23.47 MW of small hydro in-service and on-line as of October 1993 and has plans for approximately 109 MW in the

future.[19] Hydro Québec has recently signed contracts for 160 MW of small power projects, most of which are small hydro projects.[20] While there are mounting pressures against hydro development in Canada, the criticisms largely relate to large-scale facilities; government policy tends to favor small hydro development.

In sum, while there is considerable experience in both small hydro and biomass for generating electricity, predicting the viability of these resources is tenuous given the opposing interests for the use of these resources. In contrast, wind and solar resources show promise for dispersed electricity generation in North America.

2.3 Experience in Developing Countries

In contrast to Canada (and even the U.S.), developing countries appear to have far more practical field experience with RETs for dispersed electricity applications. However, efforts to popularize renewable energy conversion technologies are not generally viewed as having fulfilled expectations.[21] The reasons are many

- Evidence suggests that rural people are unwilling or unable to repair or replace failed systems from their own resources when the system periodically breaks down. Because of this, it is essential that there be maintenance services made available

- While diesel generators often are carefully maintained, the same has not been the experience with wind and PV systems. Although PV and wind systems are easier to maintain than diesel generators, it is still essential that they be serviced.[22]

- Batteries can pose significant problems in remote systems. When batteries are charged and discharged excessively and this is compounded by failure to fill the batteries with distilled water, the batteries can rapidly deteriorate.[23]

- Stocks of spare parts and lubricants needed for wind and biomass systems and distilled water for batteries are rare in the developing world

- Overhead costs for foreign consultants and contractors tend to be high by developing country standards

- Even when the electrical conversion systems are themselves cost effective, the balance of system costs can be high. The balance of system costs includes the mounting structures for PV systems, wires, switches, and batteries. If the system is not converted to AC power, the purchase of DC appliances and lighting becomes part of the balance of system costs. For example, solar refrigerators have installed costs of between $US 3000 to $US 6000, whereas a kerosene-based system costs about one tenth of the price.

- The experience with utility management of small hydro facilities seems to be regarded as 'disastrous'. Small hydro facilities run by utilities as miniature large-scale facilities tended to cost about 9 times more per kWh than large-scale facilities.

- The experience with biomass (with few exceptions) appears tarnished to the point that the future of biomass for electrical generation is viewed as being in serious jeopardy. One of the primary reasons cited is that biomass fuel is under high demand in rural communities for direct application such as cooking.

- Because of the need for considerable quantities of water, problems with corrosion of the steel cover of the biogas digester, and cracking of the structures caused by dry spells, a 'rough profile' for areas which could sustain a biomass system includes: a moist climate, a regular supply of cattle dung or other feedstock, skilled labour for the construction and maintenance, an affluent rural population, and a constraint on other fuel supplies.

These problems associated with dispersed generation applications are not exclusive to developing countries; ventures in remote Canadian communities have faced similar problems.[24]

2.4 Hurdles to and Policies Promoting Dispersed Electricity Generation

2.4.1 Hurdles

Some rather significant hurdles to the industry as a whole must be overcome. Some are symptomatic of any new technology and its market acceptance; some relate to problems experienced in the field; and some are institutional.

The barriers to widespread adoption of dispersed electricity generation technologies include the following.

(i) These resources are highly site specific and are not available continuously.

(ii) These resources may be far from population centers, requiring extensive transmission networks or battery back-up systems.

(iii) In terms of technological advances: (a) wind power systems require development of variable speed generators, (b) photovoltaics require improvement in cell efficiencies, production techniques, and balance of plant; and (c) biomass systems must have improved equipment performance and longevity.

(iv) If a maintenance and operational structure is not in place, as it seldom is in remote areas and developing countries, any malfunctions that either cause the system to go down or reduce its power outage may cause users to simply disregard the system.[25]

(v) Ill-reputable suppliers of renewable energy conversion technologies, complete with wildly enthusiastic claims and poorly performing technologies, have damaged the profile of these technologies.

(vi) It is difficult to find easy-to-interpret information on renewable technologies. The area most deficient is the solar energy industry and solar buildings.[26]

(vii) While cost has been a barrier in the past, RETs are now cost effective in terms of life-cycle cost in many off-grid applications. However, there is still a perception that they generally cost too much which can be credited in part to high up-front costs.

(viii) Demonstration sites are few and far between making transfusion of the technology difficult.

(ix) The pervasive mentality in North America is that electricity comes from the electric utility, which has long provided reliable and relatively inexpensive electricity. Old habits are hard to overcome.

(x) Electricity users do not have a 'renewable utility' to contact for information on the appropriate system for their electrical needs. They must contact wind power, solar power, etc., manufacturers to get bids, and then select the system best suited for their needs. This is quite a technical exercise, and one most laypersons would not have the expertise to analyze.

(xi) Because many of the renewable technology manufacturers are small enterprises, they often lack the financial resources to support their ventures with the necessary reliability guarantees.

2.4.2 Policies Promoting Dispersed Power

Efforts to reduce some of these barriers have been addressed by recent policy initiatives and utility programs in North America. The two predominant interests of government are to encourage renewable forms of electrical generation (e.g., through tax incentives) and to stimulate the breakup of the utility monopoly over generation. Because renewables tend to be cost effective for small niche applications, policies promoting the use of renewables tend to have the additional side benefit of also promoting dispersed electricity generation. Some utilities are encouraging dispersed electricity generation, but examples are few. The programs are briefly described in Figure 2.1.

2.4.3 Lessons from Experience

There have been some useful insights gained in North America and ıbining these with practical experiences gained in developing countries ds some valuable lessons:

(1) These technologies should be considered in symphony, not in isolation. No single dispersed electricity generation technology is likely to meet the full spectrum of electrical needs. Packages of these systems are sometimes far superior choices. Hybrid PV and diesel systems and wind/mini-hydro packages are two such examples that can offer more flexibility in power generation than the systems alone.

(2) It is not sufficient for planning institutions or departments to identify cost effective technologies and assume they will be implemented. Planning entities must also ensure that local workers learn how the technology functions, its merits and pitfalls, and its economic benefits and costs.

(3) Information comparing the technologies in a hands-on, consumer oriented manner must be provided, especially in the solar industry and solar buildings. Using test sites can dramatically increase awareness An information storehouse which is easily accessible and local would be optimal. For example, rural electrification centers for farmers.

(4) It is not clear whether electric utilities are the most effective medium for bringing about dispersed electricity generation. On the plus side, they have direct access to most potential consumers of dispersed electricity generation; they are a convenient medium for government policy; many utilities have had success with customer oriented demand-side management programs; and they have considerable experience in electrical generation. On the negative side, they tend to focus on those generation options which match their unique supply situation rather than the individual customer's needs, they tend to view the aggregate customer rather than the individual (particularly in the residential market); they tend to have more experience with large-scale, not small-scale systems; and change often takes place slowly because utilities tend to be large.

(5) Community based strategies for encouraging dispersed electricity generation appear to be having more success than large-scale public projects. Community based programs tend to be directed to the circumstances of a particular region.

(6) Certification and installer licencing--i.e., quality control--is imperative to ensure that ill-reputable manufacturers will not compromise these promising technologies.

(7) Operation and maintenance infrastructure is crucial, especially in areas where users do not have the necessary skills to maintain the systems or repair them after periodic break-downs.

(8) Line extension policies, showcase efforts, green communities, HERS, the expanded market opportunities approach to renewables by utilities, and the 'DSM' style strategies show promise in encouraging dispersed electricity generation because they deal either at the level of the customer or they are community based.

(9) Integrated resource planning, set-asides, social costing, utility incentives, green pricing, and preferential rates for independent power do not hold the appeal of the other government and utility programs because they target the utility--either to develop 'on-site' resources or to purchase renewables from independent power producers.

In the end, none of the options, even in a hybrid form, fully meet all of the requirements to make them ideal, widely used, *dispersed electricity generation options*--i.e., easy maintenance or packaged maintenance services, easy to access suppliers, moderate prices relative to income, and suitable operation at small sizes. But, improvements in the areas noted above appear to signal greater success for dispersed electricity generation options in North America in the future.

Figure 2.1
Programs and Policies that Affect Dispersed Electricity Generation

Programs/ Policies	*Description*	*Implemented By*
Existing Programs/ Policies		
<u>Government</u>		
Public Utilities Regulatory Policies Act (PURPA)	FERC's guidelines specifically direct electric utilities to purchase <u>all</u> electricity from *qualifying* non-utility generators at rates bounded by what is deemed "reasonable and just" and not exceeding the utility's *avoided costs*. A "qualifying facility" includes: (i) those generation facilities with capacity less than 80 MW for which at least 75 percent of the energy inputs come from biomass, waste burning, renewable resources, or geothermal heat, and (ii) cogeneration facilities. Once qualified, the facility is entitled to the special purchasing conditions as described above and two automatic exemptions. The Act provides an exemption from regulation as a public utility and state regulation of rates and other financial and economic matters such as equity among customers and detailed accounting requirements.	U.S. Government

Figure [illegible] (cont'd)

Programs/ Policies	Description	Implemented By
Small Power [illegible] Act [illegible]	Stipulates that utilities in Alberta are to purchase 125 MW of power from small power producers--producers which do not generate more than 2.5 MW. Purchases can be made from facilities that produce more than 2.5 MW, but only under special circumstances. The purchase rate is either 5.2 cents/kW.h for power delivered up to December 31, 1991, and 6 cents thereafter, or 4.61 cents/kW.h for power delivered in 1990 and the rate adjusted for inflation thereafter.	Government of Alberta
Class 34 Accelerated Capital Cost Allowance	Allows the company to write-off eligible assets over 3 years--up to 25 percent in the first year, up to 50 percent in the second year, and the balance in the third year	Government of Canada
Contemporary Program/Policies		
Government		
Energy Policy Act (1992)	Provided a "permanent" 10 percent business investment tax credit for solar and geothermal projects, a ten year 1.5 cent/kW.h production credit for wind and closed-loop biomass plants commissioned before 1999, and a 1.5 cent/kW.h production incentive for solar, wind, biomass, and geothermal for rural electric cooperatives and other publicly-owned utilities	U.S. Government

Figure 2.1 (cont'd)

Programs/ Policies	***Description***	***Implemented By***
Integrated Resource Planning	Utilities must provide demand-side management and customer-owned generation, and use independent power production in addition to conventional supply-side resources such that it results in the least-cost service.	Most utilities
Social Costing	Include economic costs and benefits of the impacts of business activities on society (particularly on the environment) in business decisions.	Ontario, B.C. and Wisconsin (in negotiation), California, Massachusetts, Nevada. New York, Bonneville Power Authority (quantified-in use)
Set-Asides	Governments/regulatory authorities stipulate the amount or direction of the renewables utilities are to purchase	Ontario, Québec, B.C., California, New England Electric System, New York State. Wisconsin, Minnesota, Arizona
Line Extension	Upon offering line extensions to new customers, utilities would also have to illustrate the comparative costs and benefits of alternative generation options relative to the line extension to customers.	B.C. Hydro; Montana; New Mexico; Arizona; Colorado

Figure 2.1 (cont'd)

Programs/ Policies	***Description***	***Implemented By***
Utility Incentives	Utilities would be given a financial reward for using renewable resources.	Wisconsin
Technology Showcase - *S-2000*	The Canadian federal government, in partnership with utilities, promote solar water heaters through support of field trials and monitoring.	Canadian Government: Nova Scotia Power; Hydro Québec; Guelph Hydro, B.C. Hydro
- *Mavroules Bill*	Required that the U.S. Department of Defense use cost effective solar or other renewable forms of energy. They found 21,090 cost effective applications that would save taxpayers $175 million and implemented over 1,000 of them.	U.S. Government
- *Solar Energy in Buildings Program*	The U.S. Department of Energy awarded $US 31 million towards the adoption of 843 solar systems for sixteen federal buildings. 701 were implemented	U.S Government
Green Communities Initiatives	Delivers a "Strategic Plan", funding for which can be up to 90 percent of the cost, to a maximum of $15,000. The community can then apply to the OMEE for further assistance. The second assistance package comes as: a grant, in the form of cash; products, such as energy efficient lighting; staff secondments; and/or *green home visits*, otherwise known as energy audits	Ontario Ministry of Environment and Energy (OMEE)

Figure 2.1 (cont'd)

Programs/ Policies	***Description***	***Implemented By***
Home Energy Rating System	Negotiating to include renewables within the existing "DSM" energy-efficiency package currently promoted under the program. A policy statement is expected in June 1994.	U.S. and State Governments/Utilities
Safe Harbour	Regulators would create a "safe harbour" for utilities, to allow them to research, experiment, and develop these resources without fear of regulatory prudency reviews.	Has yet to be used
<u>Utility</u>		
DSM Strategies *- Solar Program*	Solar powered pumps for livestock waterings.	K.C. Electric of Colorado
- Solar Program	Involves: (i) the solar hot water system, solar buildings, and solar cooling for dispersed applications--SMUD provides rebates of $400 to $1,450 and 3 percent, 8 year financing on solar hot water heaters; (ii) Sacramento Solar Design Handbook; and (iii) incentives and demonstration projects to encourage the use of solar technologies in cooling (in development).	Sacramento Municipal Utility District (SMUD)
- Energy Crafted Home	Waiting for information.	Seven utilities in New England
- Solar Program	The City of Austin Electric provides rebates from $150 - $350 to either commercial or residential customers who switch their electric heaters to solar powered heaters.	City of Austin Electric

Figure 2.1 (cont'd)

Programs/ Policies	***Description***	***Implemented By***
Considering Solar Programs		Southern California Edison, Palo Alto
Expanded Market Opportunities	Idaho Power would design, own, and maintain the PV systems. Customers would pay an initial fee of 5 percent of the installed cost and a fixed monthly facilities charge, which at this juncture is estimated at $160.	Idaho Power
Green RFPs	The utility would solicit bids for a certain portion of their supply needs from renewable energy producers and possibly provide a group insurance premium for renewable systems to lower the costs for each producer.	New England Power, New England Electric, utilities in California
Preferential Rates	Some utilities have preferential purchase rates or policies for renewable energy supplied by independent power producers.	Ontario Hydro; B.C. Hydro, Iowa State; Puget Sound Power & Light Co.
Green Pricing	Customers would pay a premium for the utility to acquire power from renewable resources.	Public Service Company of Colorado

SOURCES: Province of Alberta [illegible] Devine et al (1987), National Association of Regulatory Commissioners Subcommittee (1992, 1993, 1994); Sue Tierney [illegible] Ontario Ministry of Energy and Environment (1989); Claude Desjarlais, Québec Ministry of Energy, B.C. Ministry of Energy, Mines and Petroleum Resources [illegible] (1993), Dr. David Peugh, B.C. Hydro; Alliance to Save Energy (1993); Natural Resources Canada (1993); John Ryan and Richard Sellers [illegible] Nino, Ontario Ministry of Environment and Energy; Cynthia Gardstein, Home Energy Rating System Council; David Moskovitz [illegible] (1994), B.C. Hydro company reports; S. Wilson (1993); Mac Cosgrove-Davies and Dinesh Kumar (1994); John Bryne (1994); John Ezura [illegible] Idaho Power Company company reports; Keith Brown and Corinne Boon (1992), and W.J. Joerissen (1993)

2.5 Renewable Energy Program In India

The renewable energy program started with the establishment of the Department of Non-conventional Energy Sources in 1982. RETs in India are promoted through R&D, demonstration projects as well as large-scale dissemination projects. Most of these technologies have been supported by subsidies and financial incentives. In recent years, however, it was realized that faster diffusion of renewable energy sources required a greater reliance on commercialization through fiscal rather than financial incentives involving the private sector. In this direction, the most significant development has been the setting up of IREDA (Indian Renewable Energy Development Agency) in 1987, with the objective of promoting and commercializing technologies through provision of financial assistance. Short term loans are provided to projects that have good prospects of commercial success. A summary of the financial assistance for different technologies is given in Table 2.1. Table 2.2 indicates the progress of the renewable energy program in India.

IREDA financing has enabled private sector participation in a large way, especially in windpower generation. IREDA has been allocated Rs. 10 crores during the 8th Plan for its activities and funds are also being obtained from multilateral donor agencies. Recently, an agreement was signed with the World Bank for a grant of US $275 million for development of grid connected small hydro and windfarm schemes and for promotion of Solar Photovoltaic (PV) systems.

Windfarms have emerged as a viable option and with the growing interest of the private sector in this technology, capacity in wind energy is expected to increase in the coming years. Small hydro has evolved as another promising option, especially in remote, hilly areas where the cost of grid electricity is formidable. Among solar thermal technologies, solar water heaters (for industrial use) and solar cookers are gaining popularity. However, in both these technologies, attention needs to be paid to product development and to compatibility with user requirements.

As far as the costs of RETs are concerned, it has been claimed that they cannot compete with conventional energy sources. However, it is important to note that although renewables may not be defensible on purely economic grounds, environmental and social concerns make a strong case for them. RETs are endowed with advantages like environmental benignness that should be taken into consideration while calculating costs. An estimate of costs of energy from various technologies is provided in Table 2.3.

2.5.1 Windpower Generation

Wind technology in India today is fairly advanced and well established. Estimates by the Ministry of Non-conventional Energy Sources (MNES) place the ultimate wind-energy potential in India at 20,000 MW.

Another study carried out by the Tata Energy Research Institute (TERI) estimated the potential of wind resource along the coastal regions in the range of 50,000 MW. There is, however, a significant difference between the "ultimate" and the realizable potential of wind energy. This is largely due to the highly intermittent nature of wind energy and the characteristics of the grid. In general, the penetration level (indicative of the realizable potential that windfarms can make to the regional grid) in India varies between 5 percent to 50 percent depending on the generation mix on the grid. The ultimate potential at some key locations is given in Table 2.3.

2.5.1.1 Wind Energy Program In India

The first wind farms in India were installed in 1986 in coastal areas in Tamil Nadu, Gujarat, Maharashtra and Orissa. By the end of March 1994, nearly 114 MW of grid connected windfarms were operational. The performance of windfarms over the last 5 years shows an average availability of about 98 percent and the capacity utilization factor has been found to be as high as 30 percent at some locations. In this respect, it may be mentioned that some state level organizations like Tamil Nadu Electricity Board (TNEB) and Gujarat Energy Development Agency (GEDA) have taken commendable steps to deal with the constraints of an unstable grid.

In addition to setting up windfarms, the MNES has also carried out an extensive wind monitoring and mapping program to better identify sites and resource potential. The compiled data has been analyzed and is being published with the ultimate objective of preparing a wind atlas for the country. This data has already been utilized in the identification of some excellent sites for windfarms (see Table 2.4).

The increasing interest of the private sector in wind power generation is, perhaps, the most significant development in this field. When the wind power generation program was initiated in 1985/86, initially a large number of international and Indian suppliers (collaborating with international manufacturers) were encouraged to participate. Some major industrial groups with in-house R&D capability also made collaborative arrangements with reputed international suppliers for the supply of wind electric generators (WEG). By the end of March 1994, out of a total of 114 MW, the private sector had installed 74 MW of windfarms. In recent years, a number of private companies have entered into tie-ups with foreign collaborators. To ensure that this does not deter development of Indian industry, MNES laid down the condition that any private company that enters into a foreign collaboration should develop its own production capacity within a stipulated time frame.

The government also gives financial incentives to industries, such as soft loans provided by IREDA (at 14.5 percent) and a provision for 100 percent depreciation in the first year for income tax purposes. The import of

Table 2.1

Financial Assistance Package for RETS

SIN	Sector	Interest Rate (inclusive of interest tax)	Minimum* Promoters Contribution	Lending Norms of IREDA: Term Loan	Lending Norms of IREDA: Ceiling on** Term Loan	Repayment Period: Moratorium Period (maximum)	Repayment Period: Total Repayment Period (maximum)
1	Wind Farms	14 50% Rebate 0 5% for timely repayments	25%	Up to 75% of total cost of eligible items under World Bank Loan, which-ever is lower	--	1 year	6 years
2	Small Hydro	14.50% Rebate 0.5% for timely repayments	25	do	--	3 years	10 years
3	Biogas Generation	15.50% Rebate 0.5% for timely repayments	25	60% of total loan amount	Rs.1 5 Crores	2 years	8 years
4	Biomass Utilization	10 30% Rebate 0.5% for timely repayments	25	Full loan amount	--	2 years	10 years
5	Solar Energy Solar Thermal System - Manufacturers	15.50% Rebate 0.5% for timely repayments	25%	Full loan amount	--	2 years	8 years
	- Users (direct)	10.30% Rebate 0.5% for timely repayments	30%	Full loan amount	--	2 years	8 years
	- Intermediaries***		30%	Full loan amount	–	1 year	8 years

(Continued On Next Page)

Table 2.1 (Continued)

SIN	Sector	Interest Rate (inclusive of interest tax)	Minimum Promoters Contribution	Lending Norms of IREDA		Repayment Period	
				Term Loan	Ceiling on Term Loan	Moratorium Period (maximum)	Total Repayment Period (maximum)
6	Solar P.V. - Manufacturers	15.50% Rebate 0.5% for timely repayments	25%	On project to project basis	Rs. 1.5 Crores	2 years	8 years
	- Users	10.30% Rebate 0.5% for timely repayments	25%	–	–	i) 2 years (SPV Power Plants) ii) 1 year others	8 years
	- Developers		25%	–	–	-do-	-do-
7	Co-generation for Power Generation	15.50% Rebate 0.5% for timely repayments	25%	40% of project cost	Rs.3 0 Crores	3 years	10 years
8	Manufacturing of High Efficient Wood Burning Stoves	15.50% Rebate 0.5% for timely repayments	25%	Full loan amount	–	2 years	7 years
9	Pruchase of Biomass Gasifier for Power Generation	12.90% Rebate 0.5% for timely repayments	25%	Full loan amount	–	2 years	6 years for new units. 5 years to existing units

(Continued On Next Page)

Table 2.1 (Continued)

SIN	Sector	Interest Rate (inclusive of interest tax)	Minimum Promoters Contribution	Lending Norms of IREDA		Repayment Period	
				Term Loan	Ceiling on Term Loan	Moratorium Period (maximum)	Total Repayment Period (maximum)
10	Manufacturing of: a) Briquetting Equipment b) Biomass Gasifier c) Energy Conservation systems/equipment/ devices using/operating through renewable sources. d) Battery Powered Vehicles	15.50% Rebate 0.5% for timely repayments	25%	Full loan amount	–	2 years	8 years
11	Installation of high efficiency energy savings/conservation devices/systems through renewable systems/fuels	15.50% Rebate 0.5% for timely repayments	25%	Full loan amount	–	2 years	5 years for new units. 4 years for existing units
12	Purchase of Battery Powered Vehicles based on alternate fuels such as methanol, ETBE, alcohol (ethanol, hydrogen, etc.	10.30% Rebate 0.5% for timely repayments	25%	Full loan amount	–	6 months from the date of delivery of vehicle	5 years

SOURCE: Tata Energy Research Institute, July 1994.

Table 2.2

Progress of Renewables Energy Programme in India

Programme	Cumulative Achievement up to March 1993
Family-size biogas plants	1.76 million plants
Improved cookstoves	14.5 million chulhas
Domestic solar heating systems	10 292 systems*
Industrial heating systems	4 907 systems*
Solar cookers	288 028 cookers
Village provided with PV street lights	8 394 villages*
PV water pumps	756 pumps
PV power units	408.86 kWp
PV community lights/TV and community facilities	784 facilities
PV domestic lights units	14 594 units
PV street lights	29 198
Wind pumps	3 009 wind pumps
Windfarms	53.93 MW
Mini-micro hydro	93.44 MW
Biomass gasifiers/stirling engines	1 040 engines*

SOURCES. (1) Tata Energy Research Institute; and (2) MNES, 1993, Overview of programmes, Ministry of Non-conventional Energy Sources (MNES), Government of India, June.

*Installation figures up to October 1992

Table 2.3

Summary of the Cost of Energy from Various Technologies

Technology	Unit	Capital Cost	Useful Life	Capital Recovery Factor	Annual Capital Cost	Recurring Costs O&M (#)	Recurring Costs Fuel	Total Annual Cost	Annual Generation (*)	Cost of Energy
Wind farm	kW	35 000	20	0.134	4 686	1 500	0	6 186	1 752	3.53
Small hydel	kW	30 000	30	0.124	3 724	600	0	4 324	2,628	1.65
Photovoltaic (b)	kWp	110 000	25	0.127	14 025	4 220	0	18 245	1 560	11.70
Gasifier (c) agro-waste base	d kW	9 500	15	0.147	1 395	950	4 414	6 760	5 256	1.29
wood based	kW	7 500	15	0.147	1 101	750	5 992	7 843	5 256	1.49
Biogas duel fuel (d)	kW	9 500	20	0.134	1 272	950		2 222	5 256	0.42
Gasifier (c)										
agro-waste based		14 085	15	0.147	2 068	1 408	2 208	5 684	2 628	2.16
wood based		12 085	15	0.147	1 774	1 208	2 996	5 978	2 628	2.27

SOURCE: C.S. Sinha, Renewable Energy Programs in India: A Brief Review of Experience and Prospects, Natural Resources Forum, Vol. 16, No. 4, 1992.

Table 2.4

Ultimate Potential of Windfarms in Selected Districts with Highest Wind Resource

District	Waste land (sq/km)	Windfarm Potential (MW)	Wind Speed (m/s)	Specific Output at 25 M (kWh/kW/yr)	Cost of Electricity WEG (Rs./kWh)	Total Generation Over Life (GWh)
Kachch	38 640	82 998	5.25	1 607	2.87	2 668 123
Jamnagar	7 280	15 637	5.68	1 945	2.37	608 281
Rajkot	3 300	7 088	5.57	1 858	2.48	263 340
Junagad	3 080	6 615	5.58	1 866	2.47	246 814
Bhavnagar	4 400	9 451	5.35	1 685	2.74	318 466
Ratnagiri	5 980	12 845	5.22	1 584	2.91	406 994
Puri	2 700	5 799	5.15	1 531	3.01	177 528
Baleshewar	1 440	3 098	5.04	1 447	3.19	89 682
Ramanatha-puram	5 850	12 565	5.16	1 538	3.00	386 575
Coimbatore	2 220	4 768	5.38	1 708	2.70	162 895
Tirunelveli	4 950	10 632	5.84	2 073	2.23	440 770
Kanyakumari	440	945	6.43	2 546	1.81	48 126

SOURCE: C.S. Sinha, Renewable Energy Programs in India: A Brief Review of Experience and Prospects, Natural Resources Forum, Vol. 16, No. 4, 1992.

equipment was exempt from import duties until July 1991 when a 40 percent import duty was imposed. This resulted in a sharp reduction in the level of private sector activity. It was expected that such a step would give a thrust to indigenous industry. However, partly because of high taxes on locally available inputs as compared to international prices, this provided no incentive for the development of an indigenous industry as expected. Eventually, after consistent lobbying by the industry, the import duty was reduced to 35 percent.

During the Eighth Five-year (1992-97) plan, MNES plans to increase the installed wind energy capacity by 500 MW comprising:

- 100 MW government sponsored cum market development projects,
- 200 MW IREDA/World Bank/Global Environmental Facility (GEF) financed projects, and
- 200 MW private sector's own investment projects.

In recent years, multilateral funding agencies have stepped forward with significant funds for the wind energy program in India. Amounts of US$13 million from the Global Environmental Facility (GEF) and US$15 million from International Development Agency (IDA) have already been made available for the wind energy program. Another US$50 million from DANIDA has also been sanctioned.

2.5.1.2 Strategies for Increased Grid Connected Windfarms

Data from wind mapping

Since 1985, the MNES has carried out an extensive wind monitoring and mapping program to identify better sites and to assess the resource potential. The program has been implemented in a very systematic manner and the compiled data has been analyzed and published. Making the raw data available to interested institutions/industries is likely to facilitate the process of preparing detailed project reports (DPRs) more effectively and the MNES should encourage the use of this valuable data by making computerized data available to industries involved in windpower development.

Incentives to Prepare Detailed Project Reports (DPRs)

Identification of sites and designing windfarms is a specialized and expensive task. The absence of identified sites is likely to be a major hurdle if rapid deployment of wind power is sought. It will, therefore, be helpful to provide incentives for the preparation of DPRs.

Private sector participation

Though wind is probably the only renewable that can boast high private sector participation, there is need for even greater involvement and encouragement. Presently, the private companies are given certain benefits like a 100 percent depreciation in the first year, wheeling privileges, and banking of energy generated. There is a need to train personnel at the state electricity boards to identify new sites, how to install and maintain windfarms as well as prepare expansion plans.

Private investors are not fully convinced of adequate returns and therefore the schemes and policies have to be made more transparent and attractive; clear terms and conditions need to be spelt out. Particularly, better maintenance back up infrastructure at reasonable cost and less time lag should be assured.

Also, there is a general tendency on the part of the equipment manufacturers not to directly take up turnkey installations of small sets in remote areas. Instead, they seem to be content to just supply the equipment through local contractors. The solution, perhaps, lies in creating demand for a large number of sets together and look into the possibility of creating technical support facilities at the local level promoting the development of a parallel service industry/repair workshops.

TNEB is the first utility in India which offered several incentives to facilitate private sector participation. TNEB permits private parties to set up wind turbines which can, in turn, be connected to the grid. TNEB offers facilities for wheeling (a wheeling charge at the rate of 2 percent of the energy generated has to be paid) and banking of power. TNEB also purchases the surplus power produced from private windfarms at Rs. 1.25/kWh. The cost of interconnecting the windmill with the TNEB system has to be borne by the windfarm developer. The government of Tamil Nadu gives a capital subsidy of 10 percent of the capital cost subject to a maximum of Rs. 1.5 million. TNEB has also set up a wind energy development cell.

There is a need to encourage other states to take initiatives in similar directions.

2.5.2 Small Hydro Power

Generation of electricity from small-sized hydropower sources is a low-cost, environment friendly and renewable source of energy. Though the technology is centuries old, it has received wide public attention only in the last few decades.

Classification of MMHP systems:

In India, the small-, mini- and micro-hydroelectricity (MMHP) systems together are treated as small hydro power (SHP) systems covering a wide range of sizes and capacities. The classification adopted is as follows:

- Micro hydro: less than 100 kW
- Mini hydro: 101 - 2000 kW (unit size up to 1 MW)
- Small hydro: 2001 - 15000 kW (unit size up to 5 MW)

Presently, the responsibility for promoting small hydro development up to 3 MW lies with MNES, while the Central Electricity Authority (CEA) looks after hydro power from 3 to 15 MW.

2.5.2.1 Potential

A recent assessment undertaken by CEA has established a potential of about 4037 MW of small hydro in nine states. The study is currently being carried out in the rest of the Southern states and is expected to begin soon in other states. Based on the trends established so far, MNES estimates that the total small hydro potential for India up to 15 MW capacity is likely to be over 10,000 MW. About half of this is expected to be in mini- and micro-hydro categories in the hilly areas and in the North-eastern region.

2.5.2.2 Progress of MMHP in India

Until early 1989, the entire activity pertaining to MMHP development was under the administrative control of the Ministry of Power and the Central Electricity Authority (CEA). With a view to providing a sharper focus to MMHP development, the work relating to MMHP projects up to 15 MW capacity was transferred to MNES as of July 1994.

According to the latest MNES figures, 148 projects totalling 110 MW had been completed in 22 states, and 166 projects in 21 states aggregating to 202 MW are under implementation. The bulk of installed capacity is in the states of Uttar Pradesh, Arunachal Pradesh and Himachal Pradesh--out of a total installed capacity of 106.65 MW, these states account for almost 50 percent.

The Eighth Plan target for capacity addition through micro, mini and small hydro projects as per the revised strategy formulated by MNES is 600 MW. Presently, there are nine established manufacturers of mini-micro hydro equipment in the country. Most of them have had technology transfer arrangements with leading foreign firms.

2.5.2.3 Promotional Schemes

(1) Capital subsidy scheme.

A subsidy scheme has been developed by MNES for MMHP projects up to 3 MW capacity during the Eighth Plan period.

- For grid connected projects: subsidy up to 25 percent of the acceptable cost of civil works and E&M equipment including generator transformers.

- For non-grid connected[27] projects (irrespective of grid connected or non-grid connected in case of North-eastern or hilly regions): subsidy up to 50 percent of the acceptable capital cost of civil works and E&M equipment including the transformers. Power from the MMHP projects not connected to the grid or in North-eastern region and hilly regions, is to be sold at reduced rates based on a cost of generation calculated after netting out subsidy element from the capital cost.

These subsidies are available for projects only up to 3 MW. However, soft loans are available from IREDA for projects up to 15 MW.

(2) Soft Loans through IREDA

The Indian Renewable Energy Development Agency (IREDA), a public sector undertaking launched by MNES, offers soft loans to private sector entrepreneurs for setting up MMHP projects. A World Bank loan of US$ 70 million has been secured over and above IREDA's resources for this purpose.

(3) Incentives for Portable Micro-Hydro Sets

A promotional scheme for light-weight, portable micro-hydro sets for remote, hilly areas and for the North-eastern region of the country has also been announced The scheme is meant only for areas which are unelectrified and not likely to be electrified in the near future. The scheme will cover distribution of light-weight portable sets of up to 15 kW generator output, including control panel and electronic load controller. It is proposed to distribute 50 sets to begin with

(4) Incentives for DPRs

Incentives have been framed for undertaking detailed survey and investigation work, and for preparing the DPRs. Fifty percent of the actual cost of preparation of DPRs is given as grants-in-aid.

(5) Fiscal Incentives

The following fiscal incentives are available to prospective developers of MMHP schemes:

- Power generation schemes involving capital outlays up to Rs. 250 million can be taken up/sanctioned by the state governments without obtaining prior techno-economic clearance from the Centre.

- Tax holidays as applicable (at least till 1997) for all power generation projects equally apply to MMHP projects.

- Concessional customs duty at 20 percent can be secured for project imports for setting up of MMHP projects.

- 100 percent depreciation under income tax is under consideration as already applicable to other NRSE systems.

The development of the MMHP technology in India has been rather slow. The major obstacle in the promotion of this technology has been the high capital cost involved. Recognizing this, the Ministry adopted an approach of reducing the costs through standardization, adoption of a canal or cluster approach so as to achieve large volume of turnover, and careful planning to achieve short gestation periods.

A recent study by TERI on the status and effectiveness of MMHP technology in India identified some important institutional and operational constraints.

- Problems in carrying out detailed survey and investigations and preparation of DPRs

- Problems in land acquisition, allotment and handing over of sites to developers

- Delay in statutory State Government clearances

- Lack of coordination between various agencies involved such as State Nodal Agency/SEB, Irrigation Department, Power Department, Environment and Forestry Department, etc.

- Poor infrastructural facilities and accessibility in North-eastern and other hilly regions

- Time over-runs often leading to cost over-runs, compounding the shortage of funds

2.5.2.4 Strategies for MMHP

The major focus for development of mini-micro hydro power in India should be on developing and promoting standardized packages to suit different regions and local conditions; encouraging manufacture of quality equipment, their testing and certification; survey, investigation, and compilation

of a countrywide database on prospective sites; and close monitoring during project execution. The following specific suggestions may be useful in achieving these objectives.

- Concerned state agencies should keep a number of schemes readily available to be offered to private developers; for these schemes, statutory clearances like techno-economic, environmental and forest clearance, etc. should have been obtained.

- R&D work should be initiated to evolve low cost, durable and trouble free designs as well as construction methods. A recent World Bank survey reveals the possibility of bringing down the unit cost of small hydro plants (which are currently in the range of Rs. 30,000-40,000/kW) by one-third.

2.5.2.5 Institutional Aspects

There are a number of institutional and implementational aspects that need to be looked into and refined to give a boost to the MMHP program in India. There is a need to streamline and simplify the procedures involved for MMHP projects. For example, the procedural formalities involved in the following could be simplified:

- As per existing regulations, techno-economic clearance for a scheme costing more than Rs. 250 million has to be referred to the Central Electricity Authority. This could, instead, be vested in the state authorities themselves.

- MMHP up to 1 MW could be completely exempted from environmental clearance.

- Simplification/standardization of specifications, tender documents, contract and agreement formats should be undertaken.

2.5.2.6 Increasing Reliability

The reliability of the small hydro system can be substantially increased by linking it to a local grid. The grid network acts as a buffer which helps in evening out the fluctuations in load. However, there are high costs involved in extending the network to remote areas over difficult terrain. In view of this, it is recommended that wherever the grid is nearby, the possibility of extending the same to the MMHP installation should be examined. Alternatively, local grids could be developed in remote locations in such a way that three to four MMHP stations feed into them. These local grids, in turn, may eventually be connected to a regional grid.

2.5.3 Biomass Gasification

Gasification is a thermochemical process in which fuel gas is formed as a result of partial combustion of biomass (or any organic material). The process breaks down biomass to yield gaseous products.

The main advantage of the gasification technique is that it enables solid biomass to be converted to a more convenient and versatile fuel form with only minor loss of energy during the process. For many rural applications, air gasification is the most suitable approach, and its potential is tremendous. The highest potential for rural areas is for small-scale power applications. For industrial heating, equipment using oil or natural gas can be easily modified to run on producer gas, and overall conversion efficiencies (up to 70-80 percent) comparable to direct combustion can be achieved. For large-scale power generation, the gas can be used as a fuel for both gas turbines and steam generators. The substitutability of producer gas for diesel and petrol in IC (internal combustion) engines, and the relative simplicity of its production makes producer gas an attractive alternative wherever competitive fuels are either scarce or expensive. Gasification has a vast potential for rural lighting applications. There are about 550,000 villages in India; about 85 percent of the villages are electrified, but only about 30 percent of the households are electrified.

There are over 80,000 villages with a population less than 500 that are unelectrified. Assuming that biomass (wood waste, crop residues, etc.) is available, installation of biomass gasifiers is feasible in all those villages where grid electricity is difficult to reach. It is possible to meet all the domestic energy requirements of a village through biomass gasifiers of 20 kWe to 100 kWe capacity.

2.5.3.1 Gasifier Program in India

The gasifier program in India was launched in 1986 by the MNES based on 3.7 kW wood-based gasifiers, of which over 1000 have been installed to date. Until December 1992, about 7.9 MW had been installed. One evaluation, covering approximately 20 percent of the gasifiers installed by 14 nodal agencies in India, found that a little under 45 percent of the systems were in use with just 14 percent being used in the dual fuel mode. Over 25 percent of the gasifiers were either used intermittently (about 7 percent) or not used at all, with the gasifier being a probable means of obtaining a diesel pump set at a cost lower than the market cost (18 percent). Nearly 57 percent were never used after commissioning, while a little under 5 percent were never commissioned, even though the gasifier had been delivered at the site of installation. Even for working biomass gasifiers, field level performance is not very well documented. The evaluation of the reliability of gasifier technology, though now considered nearing commercialization, is therefore difficult.

The main obstacles for small-scale gasifier-based technologies are: (1) technology is still not well developed with gasifier design procedures essentially based on empirical principles; (2) the cost of operating such systems is sensitive to the price of biomass, which shows a high degree of regional variation, making the costs of energy from gasifiers site specific; (3) an estimated one hour of maintenance per day of operation is required for the gasifier and a significant level of skill is required for routine maintenance; and (4) size and weight of the system limits mobile gasifier operations and constrains fuel storage and feed. For this reason the use of gasifiers for static power applications appears to be a more attractive option at present.

2.5.3.2 Strategy for Promoting Biomass Gasifiers

The previous subsidy system promoted by MNES had a number of weaknesses. The subsidy given was so high that the whole system was available at a price less than that of the DG (Diesel engine generator) set itself. Also mainly small systems of 3.7 kW were largely disseminated where the saving was just marginal. In the villages, gasifiers should be either linked to plantations for biomass requirement or agricultural residue-based systems, to avoid depletion of the existing biomass. Saw mills and rice mills are locations where gasifiers could be used for captive power generation. It is possible to connect the gasifier systems to the existing captive power generation systems.

2.5.4 Photovoltaic Technology

Solar PV technology converts sunlight directly into electricity in an environmentally clean manner. PV systems can play an important role for remote areas where grid extension is difficult and costly. At present, the largest economically viable application for PV cells is telecommunications, although PV use for rural lighting, education, and vaccine refrigeration also have significant social benefits. The application of PV technology has been restricted so far in India because of its high cost. According to a study conducted by TERI, at 1991 costs, the economic cost of power from a stand-alone PV lighting system was computed to be Rs.19.98/kWh (as compared to Rs. 1 50/kWh for the electric grid and Rs. 1.26/kWh for small hydro)

2.5.4.1 PV Program in India

The Department of Science & Technology (DST) initiated an integrated national program on terrestrial solar photovoltaic in 1975 where scientific research on solar cells and development of PV materials was entrusted to the R&D laboratories and academic institutions. Product development was assigned to Central Electronics Limited (CEL) a public sector company.

Over the last decade the program has made substantial progress and the total installed manufacturing capacity in the country is 5.75 MW per

year. Much of the rural PV installations have occurred as a direct result of demonstration programs of MNES. Of the total PV installations, 30 percent were on a commercial, unsubsidized basis for telecommunications, signalling, defense and similar applications. The remaining rural demonstrations were primarily in domestic lighting, street lighting, water supply, and community services. Small, village-level power plants with array sizes ranging from 1 to 10 kw are also being installed in unelectrified villages.

2.5.4.2 Status of PV Program in India

The PV industry in India is relatively new as compared to the international industry. The commercial production of solar cells and modules in India started in 1983-84 in two public sector organizations, but the actual growth of the PV industry appears to have started only recently. Currently, India has indigenously developed technology and production from the stage of silicon material to the final PV system integration for crystalline silicon based PV devices. The annual turnover of the PV industry is around Rs. 50 crores. While cell and battery manufacture is dominated by a few large companies, a number of small and medium-sized private firms have entered the manufacture of sub-systems and assembling total PV systems with modules procured from one of the large manufacturers.

The allocation for the PV program is Rs. 90 crores for the Eighth Plan. In addition, a sum of US$ 55 million has been sanctioned for market development from the Global Environment Facility for a five year period corresponding to the Eighth Plan period. During this period, 3 MW of installations were planned; this was later revised upwards to 25 MW.

Several fiscal and financial incentives are given to support PV technologies. Import of PV modules, components and systems are allowed on Open General License, but are subject to customs duties. No sales or excise duties are imposed on PV systems. The government also offers depreciation under the Income Tax Act for individuals and businesses investing in PV systems.

2.5.4.3 Constraints in the PV Program

The largest problem in the PV Program in India has been the failure to create a post-installation infrastructure. This has resulted in poor field performance of the PV system as a whole, which is not due to the failure of PV device, but due to sub-standard system components and poor system design.

The reliability of rural PV applications has been generally poor. Early street light installations faced numerous problems due to component failures, vandalism, and poor consumer acceptance. This has led to a credibility

crisis for the technology, especially in rural areas. The main reasons for the poor reliability and performance are:

- lack of involvement of the beneficiaries in decisions relating to the installation of PV and its use;
- non-availability of spare parts and components;
- lack of comprehensive training on system maintenance; and
- low awareness levels about the PV systems.

2.5.4.4 Strategy for Future Growth

Considering the high cost of PV technology (more than Rs. 250,000/kW as compared to Rs. 30,000/kW for wind power and Rs. 25,000/kW for small hydro), there is a need to rethink the policy to promote the technology on a large scale. While PVs can be promoted for very specific purposes in small, remote and specialized applications where the cost of providing grid supplies is high or the quality of power required is high--such as vaccines refrigeration, telecom, railway signalling, cathodic protection etc.--efforts must be made for cost reduction prior to promotion of widespread application of PV systems. The following steps would enhance the effectiveness of the PV program.

Fiscal Incentives

The effect of import duties on the price of PV is far greater than the direct cost impact. The interest charges on funds borrowed to cover the payment of duties can only be recovered several months later. Import duties are also partially responsible for the lower reliability of a number of PV systems, especially consumer items such as lighting where the buyer (usually the state nodal agencies who have to finance the system cost apart form the module) is unwilling to pay a high premium for extra reliability. The high duty on electronic components has forced many manufacturers to build their own controls and inverters instead of importing the systems.

Because manufacturers build small quantities of products, unit costs are high and, as a result, the design specifications may be compromised in order to reduce costs. The resultant loss of reliability and efficiency has a detrimental impact on acceptance of PV products. Further rationalization is needed to improve the duty structure

Post-installation Service Facilities

The lack of an effective, after-sales service network has been a hindrance to the broader acceptance of the products. The consumer

acceptability of PV system is influenced not only by the quality of the service supplied, but also by how promptly any technical problems can be corrected.

More often than not, the participation of the Government ends with the installation of the system. Post-installation maintenance (or arranging for the same) is the responsibility of the community or institution which currently has no influence on the choice of supplier or manufacturer.

2.5.5 Solar Thermal Technologies

Solar thermal energy utilization, by definition, implies the conversion of solar radiation into thermal energy, or heat. Solar thermal systems have been classified on the basis of the temperature of utilization as low (<100°C), medium (100-400°C), and high (>400°C) temperature applications. From an end-use point of view, areas of solar thermal energy utilization are traditionally classified as: solar water heating, solar cooking, solar air heating (drying), solar cooling, solar passive architecture, solar ponds, desalination, solar (thermal) water pumping, and solar (thermal) power generation. The most popular applications are solar heaters and solar cookers.

2.5.5.1 Solar Water Heating

Use of simple, low temperature collectors for providing hot water is the oldest and most widely accepted application of solar energy. In India, solar IPH (industrial process heat) applications have been the most popular application followed by domestic water heating systems. As of December 1992, 5159 solar water heaters for industrial use and 10,432 domestic solar water heaters were disseminated. The estimated market size is 10-20 million m^2 in the industrial sector and about 1-2 million m^2 in the domestic sector. In spite of such large physical potential, the solar hot water business is not exactly booming.

In fact, several earlier stalwarts like Jyoti, HBB (currently ABB), and Best & Crompton have terminated manufacture of solar water heating systems. The economics of the systems are perhaps responsible. Currently, the installed cost of a solar hot water system (at about 60°C) is Rs. 100 per litre per day. Apart from cost, solar water heaters face certain operational problems like scaling in the pipes. The calculation of NPV (net present value) of benefits (without subsidy and other fiscal benefits) indicates that at the present initial costs, the solar water heating system is not capable of standing on its own in the market, except when it is saving electricity throughout the year.

Strategies for increasing the penetration of solar hot water systems are given below.

Identifying the correct market segments

Since solar water heating systems appear to be cost effective only when hot water is required throughout the year, institutions (like hotels and hospitals) satisfying this criterion (and using electricity for water heating) are the best target segment for domestic hot water systems. A number of industries like textiles also require hot water for their operations.

Improving Performance

There is a need to encourage entrepreneurs and research institutions to take initiatives to develop innovative designs or improvements. Result-linked financial support can be provided for such activities. The system performance, both short term and long term, should be the main criterion for promotion.

- A major problem experienced by the users of solar systems is related to scale formation. The water supplied in most Indian locations is hard and causes scale formation which, due to the peculiar geometry of the flat plate collector, is difficult to remove. Hence, any research aimed at rectifying the affected systems or at controlling or eliminating scale formation, should be encouraged.

- A serious limitation of the currently available water-in-tube flat plate collectors is that they cannot be used in hilly areas which frequently experience sub-zero temperatures. From an ecological point of view, use of solar water heaters in the hilly areas is highly desirable and hence development of heat-pipe based collectors and collectors with phase changing fluids could be given a top priority for R&D. There have been attempts in the past in this direction but none have resulted in commercial manufacture in India.

2.5 5.2 Solar Cooking

Studies have shown that cooking with solar energy is cheaper than cooking with electricity, but is costlier than most other available options such as LPG, kerosene, biogas, firewood, etc. Solar cookers offer the additional advantage of being environmentally friendly and a zero cost of operation to the user. The type used in India is the box-type solar cooker which is sold on the market for about Rs. 1000 (exclusive of the government subsidy).

The program of solar cookers as a cost-sharing scheme was launched by the Government in 1982. As of March 1993, approximately 288,000 solar cookers had been disseminated in the country. The critical commercialization issue is to develop a more user-friendly and convenient cooking device. It is important to note that the nature of the product is a limiting factor to its dissemination. Solar cookers have rather limited applicability, as they can only perform the boiling operation and hence are not a

complete cooking system. Further, they can not be used at night or during cloudy days, and the cooking is slow.

As a product, the conventional box-type solar cooker suffers from certain constraints. It is too bulky to be handled easily, there is no provision to clean the space between the two windows of the double glazing, the glass wood insulation gets spoiled if the cooker is exposed to rain, and the quality of the utensils is poor.

Strategies for increasing the market penetration of the solar cooker include:

Product Development

The major goal for this technology should be to develop a more user friendly device. While doing this, the design attempt should be towards a more flexible and reliable cooker--different collector size, possibility of electrical back-up, greater choice of vessels, better design effort. Such a development effort is best done by an entrepreneur or manufacturer, but these at present operate at a very small level and have no capacity for carrying out any in-house R&D. Thus, there is a strong need to promote R&D in the following areas:

- improving its performance;
- flexibility in the amount of food that can be cooked; and
- making the cooker more aesthetically appealing.

Identifying the market

Since the solar cooker is not a complete cooking system and supplements whatever cooking system is being used by saving fuel, the relevant markets are households using commercial fuels for cooking. As discussed above, convenience (which includes availability of the fuel) plays a decisive role in determining the choice of cooking technology. LPG is, therefore, the most preferred fuel choice. The widespread shortage of this fuel, much more severe in smaller towns, would indicate that the most attractive market segment would be households using commercial fuels who are willing to pay a premium of about a thousand rupees to decrease the inconvenience of the uncertainty of the availability of the preferred fuel. A much larger number of such households are likely to be found in towns and cities as opposed to metropolitan centres.

Marketing infrastructure

Commercial success of any product demands visibility in the market and ease of availability. Higher penetration of the solar cooker requires an increase in the number of retail outlets. One attractive outlet would be LPG

dealers. It is only in recent years that solar cookers can be purchased off the shelf. This needs to be promoted further.

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Chapter 3

CLEAN COAL TECHNOLOGIES

3.1 Introduction

Coal is the world's most abundant fossil fuel--it comprises 70 percent of the heat content of global fossil fuel reserves and it represents 28 percent of the world's annual energy consumption. At current production rates, existing coal reserves would last 200 years. About 35 percent of the world's electricity generation is powered by coal and this is expected to increase to nearly 40 percent by the year 2010. Coal is expected to remain the fuel of choice for electricity generation in the foreseeable future. However, the use of coal carries with it several environmental concerns. New clean coal technologies (CCTs) offer the potential for significant reductions in environmental emissions when used for power generation. These technologies may be utilized in new as well as existing plants and are therefore an effective way of reducing emissions in the world's aging inventory of coal-fired generating units.

Several of these systems are not only very effective in reducing SO_2 and NO_X emissions but, because of their higher efficiencies, they also emit lower amounts of CO_2 per unit of power. CCTs can be used to reduce dependence on foreign oil and to make use of a wide variety of coals available either domestically or in the world coal markets.[1]

3.1.1 Technological Options for Clean Coal Utilization in India[2]

India has large coal reserves (192 billion tonnes) but the bulk of these reserves are below the quality standards of internationally traded coals. Indian coals are predominantly of high ash content and low sulphur (below 0.6 percent). Over 60 percent of coal resources are inferior quality with a Gross Calorific Value (GCV) of 4000 kcal/kg or less. Coal constitutes about two thirds of total commercial energy consumption in India. Coal consumption has grown at an average annual rate of about 5.5 percent over the past two decades and is projected to increase at a lower rate in the next two decades. The coal consumption pattern in different sectors are given in Table 3.1.

Table 3.1

Trends in Coal Consumption by Sector
(million tonnes)

Sector	1970-71	1980-81	1989-90
Railways	15.6	11.8	5.7
Power (utilities)	13.2	33.2	113.0
Power (captive)	*	*	12.0
Industries (iron and steel)	13.5	21.0	28.4
Industries (others)	22.0	31.5	35.2
Domestic and others	6.9	6.9	5.3
Total	71.2	104.4	199.6

*Included in other industries.

SOURCE: Tata Energy Research Institute.

The pattern of coal consumption has changed significantly during the last two decades. The railways, who were the largest consumers until the early 1970s, have adopted a policy to phase out steam locomotives and hence their consumption has been declining. Coal-based thermal power stations are the largest consumers followed by steel and cement industries. The power and industries sectors together accounted for about 94 percent of total coal consumption in 1989-90.

The environmental consequences of increased coal use are recognized by India's energy and environmental planning agencies. There is a growing realization that coal-related environmental problems must be controlled in the future through application of clean coal technology in the various consuming sectors. The technological options for reducing coal consumption and environmental impacts in major coal consuming sectors are discussed in the following paragraphs.

3.1.1.1 Steel Sector

The steel industry is one of India's most energy intensive industries and consumes nearly 10 percent of the total energy requirements of the industrial sector. In integrated steel plants, coking coal contributes from 66 to 80 percent of the total energy inputs from primary sources. The specific energy consumption per tonne of crude steel is very high (12 Gcal/tonne) compared to the average of 5.5 Gcal/tonne in other major steel producing countries. The primary factors behind this high energy intensity are the poor quality of indigenous coking coal and the continued use of outdated technologies like the open-hearth furnace. The steel industry imports good quality coking coal and blends it with indigenous coals to get coal of the desired quality. Modernization plans have been drawn up for the steel plants. The major technological changes proposed are:

1. movement to larger unit sizes for the major production units such as, coke oven batteries, sinter machines, blast furnaces, and BOF converters; and

2. increasing the productivity of the operating units and reduction in consumption of raw materials per unit output.

Some areas which are receiving attention for improvement are mentioned below.

- Technology development in the area of coke production to improve coke strength and lower ash content. This includes groupwise crushing of coal, partial briquetting of coal charge (PBCC), introduction of stamp charging, and computerized combustion control.

- Blast furnace burden would be fully prepared with at least 70 percent sinter, 10-15 percent pellets, and the balance lump iron ore of size 8-25 mm.

- Modification of blast furnace stoves to increase the hot blast temperatures above 1000°C;

- Auxiliary coal dust injection or natural gas injection in the blast furnace to reduce coke consumption.

- Lime dust injection system.

- BOF technology to replace open-hearth and other old technologies.

- Introduction of continuous casting technology.

- Waste heat recovery at every process stage.

3.1.1.2 Cement Sector

Three types of processes are used in India to manufacture cement: wet, dry and semi-dry. The dry process is technologically advanced and is less energy intensive. In 1977, only 24 percent of capacity was based on the dry process but by 1989, its share had increased to 75 percent. Since 1975, all new capacity additions have been based on the dry process.

The technologies available for reducing energy consumption are:

- adoption of only dry process technology in future capacity additions;

- using natural gas in cement plants in Andhra Pradesh, Gujarat and Assam; and

- supply of beneficiated coal to the cement sector.

3.1.1.3 Power Sector

The installed electricity generation capacity in utilities in India at the end of 1989-90 was 62,534 MW and the total generation during the year was about 233 TWh. Approximately 67 percent of the installed capacity is coal-based thermal plants which contribute over 70 percent of the total electricity generated. Table 3.2 shows the changes in the production mix of electricity as well as some performance indicators over the past two decades.

Table 3.2

Performance of the Indian Power Sector

	Installed Capacity			Gross Generation			Annual Specific Generation (kWh/kW-year)	
	Hydro	Thermal	Total	Hydro	Thermal	Total	Hydro	Thermal
1970-71	43.4	53.7	14709	45.3	50.5	55.8	3956	3562
1975-76	42.1	54.7	20117	42.1	54.7	79.2	3935	3932
1980-81	39.0	58.1	30214	42.0	55.3	110.8	3947	3940
1982-83	36.9	60.6	35363	37.1	61.3	130.3	3705	3724
1986-87	32.9	64.4	49266	28.7	68.7	187.7	3324	4060
1989-90	31.8	65.4	62354	27.2	70.3	233.0	3187	4005

SOURCE: Tata Energy Research Institute.

Some of the power generated in a thermal power station (TPS) is used to run plant auxiliaries, such as coal grinding mills, air blowers, electrostatic precipitators (ESP), etc., and some power is lost in transformation (to transmission voltage), switching, etc. Presently, at the national average, about 10 percent of the power generated in a TPS is used internally. Consequently, the net conversion efficiency is 90 percent of the gross conversion efficiency.

The efficiency of coal conversion in Indian thermal power stations is low: the average gross conversion efficiency is about 28 percent, and the average net efficiency is about 25 percent. More than 70 percent of the country's thermal capacity operates at efficiencies below 30 percent; 25 percent of capacity operates at efficiencies below 25 percent. The present design gross efficiency is about 36 percent. Therefore, enhancing TPS performance to increase the operating efficiency to the design efficiency would increase aggregate power output (at the same coal input rate) by nearly 15 percent. This implies that CO_2 emissions per kWh would decrease by nearly 12 percent.

The age distribution of thermal plants in India is given in Table 3.3. It shows that nearly half of the existing TPS are over 15 years old and less than 150 MW capacity. These plants have lower thermal efficiency and consume more coal per unit of electricity produced than higher capacity, more recently built plants. The principal causes of low TPS efficiency are poor and varying

quality of coal and poor maintenance and operating practices. High-ash coal, by itself, does not lower the efficiency (in fact, boilers burning high-ash coals have the same design efficiency as those burning low-ash coals). However, coal quality has declined significantly compared to specifications for original plant designs. Coal being supplied to TPS is largely from opencast mines and has some non-coal material (shale and rock) mixed with it. This results in poor combustion, as well as in a high power requirement for grinding.

Table 3.3

Age-wise and Capacity-wise Distribution of Thermal Power Plants

(years)

Plant Capacity	<5	5-10	10-15	15-20	20-25	>25	Total
15-100 MW	14	15	10	18	44	74	175
100-150 MW	5	20	24	25	5	3	82
200-210 MW	29	39	18	-	-	-	86
500 MW	8	1	-	-	-	-	9

SOURCE: Tata Energy Research Institute.

Poor TPS operating practices include unnecessary use of fuel oil for flame stabilization, steam pressure excursions, high excess air, inefficient ejector operation, poor quality of water supplied to turbine condensers, and inappropriate angle of burners in boilers. Improper maintenance of coal mills, insulation, and high pressure heaters are other leading causes of low efficiency.

3.2 Overview of CCTs

Clean coal technologies can be installed at any of three stages in the fuel chain, or in a fourth manner that departs from the traditional method of coal burning.

- Precombustion - sulphur and other impurities in coal are removed before the coal reaches the boiler.
- Combustion - pollutants inside the combustor or boiler are removed while the coal burns.
- Post-combustion - flue gases released from coal boilers are cleaned in the ductwork leading to the smokestack or in advanced versions of todays scrubbers.
- Conversion - the combustion process is bypassed altogether; coal is changed into a gas or liquid that can be cleaned and used as a fuel.

3.2.1 Precombustion Cleaning

Traditionally, research to improve precombustion cleaning has concentrated on two major categories of cleaning technology--physical cleaning and chemical cleaning. Recently, biological cleaning has attracted interest as advances have been made in microbial and enzymatic techniques for removing sulphur from coal.

3.2.1.1 Physical Cleaning

Virtually all coal cleaning today is done with physical techniques which separate undesirable matter from coal by relying on differences in densities or variations in surface properties. When coal from the mine is crushed and then washed, the heavier impurities are separated. But physical cleaning can remove only matter that is physically distinct from the coal, such as small dirt particles, rocks and pyritic sulphur (sulphur that is combined with iron particles). It cannot remove nitrogen or sulphur that is chemically bound to the coal (organic sulphur) (Figure 3.1).

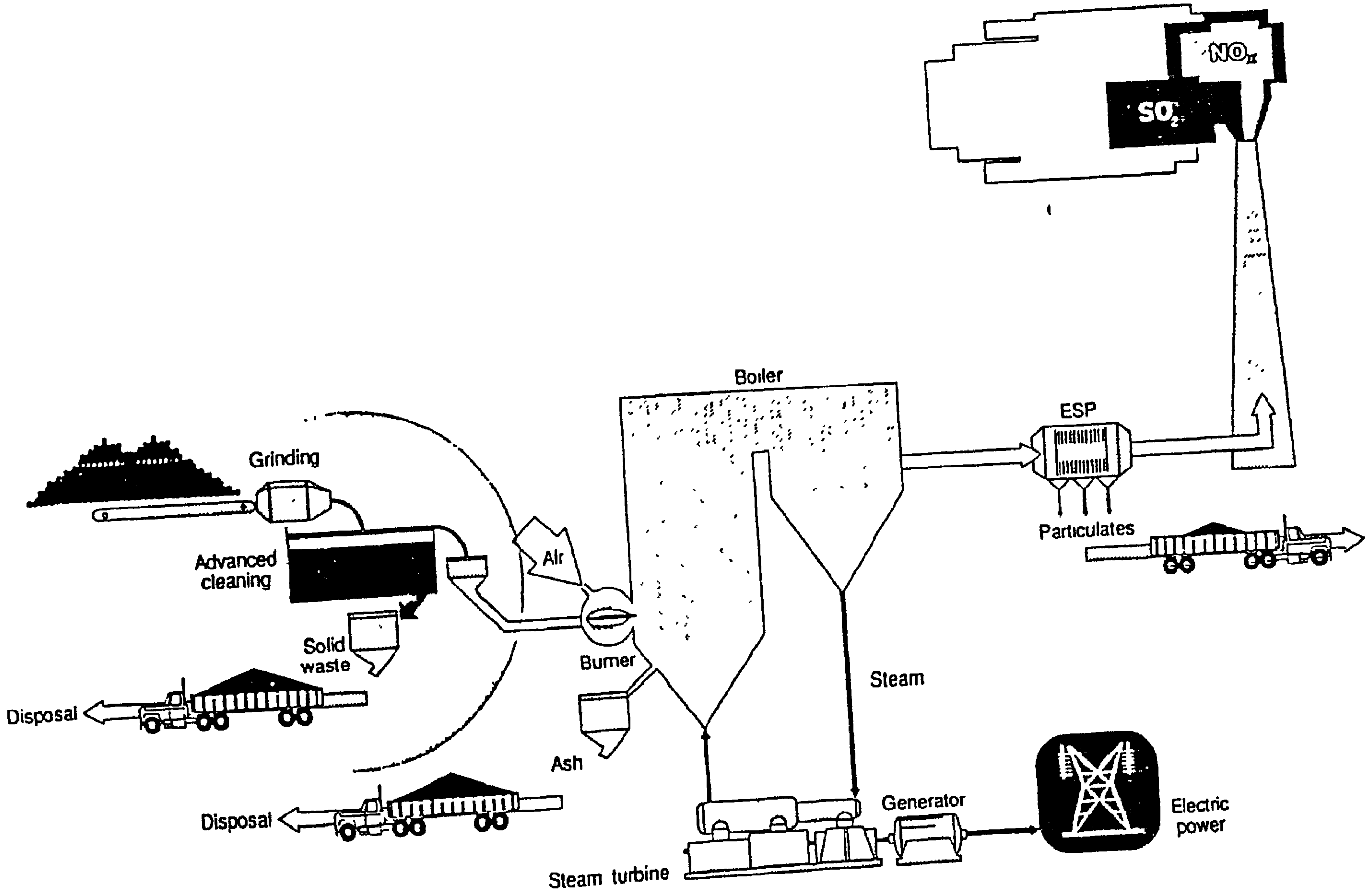
Physical cleaning processes in use today can remove 30 to 50 percent of the pyritic sulphur or 10 to 30 percent of the total sulphur in coal and about 60 percent of the ash-forming minerals. Advanced physical cleaning techniques boost cleaning effectiveness significantly by first grinding the coal into much smaller sizes than is done commercially today. Once it is finely ground, a host of new processes specially designed to work with ultrafine particles can be used to remove more than 90 percent of the pyritic sulphur and other undesirable minerals from the coal.[3]

Thermal power station plant performance in India could be improved through the following measures.

(i) Technological improvements that include replacement of existing components by more efficient versions such as tower type boilers, regenerative turbines and ball mills.

(ii) Washing of non-coking coal· Washing of non-coking coal can enhance generation efficiency. Many existing utilities were designed for comparatively low ash coals (30 percent) but are receiving coals exceeding 40 percent ash. Because of this deterioration in quality, combustion efficiency has declined. Additionally, in all units (old and new), the mills require more power to grind coal.

Figure 3.1
Advanced Precombustion Cleaning



SO2 EMISSION REDUCTION	NOx EMISSION REDUCTION	COMPARED WITH CONVENTIONAL TECHNOLOGY* PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
30-90%	No Change	Small Increase	No Change	Slight Extension	6-21 MILLS/KWH	Additional Fuel Cost Only

* CONVENTIONAL COAL-FIRED ELECTRIC POWER [illegible]

SOURCE: Clean Coal Technology The New Era United States Department of Energy January 1991 DOE/FE-021 7P.

The main purpose of washing would be to remove extraneous matter (shale and stone) that comes with the coal deliveries. It would be difficult to exactly project the efficiency increases that would accompany the use of washed coal. The experience with using washed coal for power generation in a month long trial in a 210 MW unit at the Satpura power station indicated that unit efficiency increased from 25.6 percent to 28.4 percent and auxiliary power consumption fell from 10 percent to 8 percent. The plant availability increased from 73 to 96 percent and carbon dioxide emissions fell from 0.983 to 0.866 kg CO_2/kWh delivered as a result of using washed coal.

The economic advantages of coal washing in the Indian context are well documented. Washing costs are generally in the range of Rs. 100-180 per tonne ($3 to $6/ton) which is more than offset by transportation cost savings, even if no credit is taken for availability improvements in the power plant. The consensus view is that coal washing is justified whenever transportation distances are greater than about 1000 km.

The main reason for not going in for washing non-coking coal is related to financial problems faced by both the power sector and the coal sector and the extra cost incurred in washing which, according to the coal companies, is to be borne by the consumers. However, from the environmental perspective, the most important benefit of coal washing would be the impact on pollution control equipment. The Satpura trial showed a dramatic increase in overall ESP efficiency. If washing of non-coking coal is taken up on a large scale in a phased manner, particulate emissions from TPS would be reduced significantly. The heat value of washery rejects can readily be exploited by combustion in an atmospheric fluidized bed combustion (AFBC) boiler located at the washery for power generation and local consumption. Moreover, utilization of washery rejects addresses, at least in part, the problem of finding an environmentally sound method of solid waste disposal.

Beneficiation Technology

Coal beneficiation removes rock and shale from coal resulting in improved performance of power stations because of the availability of a better grade of coal, reduction in emissions, and savings in transportation costs. Indian coals, being high in Near Gravity Material (ngm) and of unsatisfactory crushing characteristics, are not amenable to dry beneficiation by conventional rotary breakers and dry shale extractors (spring - leaves type). Wet washing of coals is, therefore, inevitable. Jigs are considered adequate for a standard two product beneficiation. Jigs also offer cost effective technology with a clean coal yield of 75-85 percent at about 34 percent ash content.

(i) Moving screen jig (ROM jig) uses mechanical movement of a pan/screen plate in a pool of water to stratify the coal and extraneous participles. This jig can handle large particle sizes up to 400 mm. ROM jig installation is in place at Bina opencast mine in the

Singrauli coalfield. Once actual operating data for this plant are available, more such plants could be installed.

(ii) Modular Barrel-cum-Cyclone washers using coal slurry as the medium have been developed in the U.K. These are used for recovery of good coal from the washery rejects and old stock piles. One such plant is under trial at Lodna Colliery in Jharia coalfield. Once the efficiency of this technology is established more plants could be installed. This technology has the advantage of modular construction and even smaller units can be installed depending upon the nature of raw feed to be treated. This would be useful for coal consumers such as cement plants, sponge iron plants and other industries having small to moderate consumption of coal.

Additional processes that may be adopted for beneficiation of non-coking coal are: (i) deshaling of coarse coal by ROM Jig or H.M. Drewboy; and (ii) standard Jig Washing. In process (i) the reduction in ash is marginal (only to the extent of the stones and shales being removed) and coal of uniform quality is obtained. Process (ii) is adopted to yield 34 percent ash coal (ash reduction is 6-8 percent).

3.2.1.2 Chemical/Biological Cleaning

Removing organic sulphur presents a far greater challenge for precombustion coal cleaning, causing scientists to turn to techniques that use chemicals or biological reactions to separate the sulphur within the coal. Molten-caustic leaching, where coal is exposed to a hot sodium or potassium-based chemical, is a technique that has shown promise. The chemical leaches sulphur and mineral matter from the coal. Other advanced methods being studied modify the chemical characteristics of coal in a way that makes the coal more receptive to cleaning techniques.

A new family of coal cleaning, biological cleaning, is being tested in the laboratory. Researchers have identified naturally occurring bacteria that can desulphurize coal. Scientists are improving the sulphur-removing characteristics of these microbes, particularly their speed in eating organic sulphur.

Chemical or biological coal cleaning appears to be capable of removing as much as 90 percent of the total sulphur in coal and some chemical techniques may also remove 99 percent of the ash.[4]

3.2.2 Combustion Cleaning

Coal can also be cleaned while it burns. In most conventional coal combustion plants, raw coal is pulverized into small particles and injected with hot air into burners along the lower portion of the hollow rectangle called a

steam boiler. Coal burns in a long, luminous flame in the huge furnace cavity at temperatures of at least 2700 degrees F. The heat is transferred to water-filled tubes welded into the sides of the boiler and boiling water in the tubes creates steam that spins a turbine generator which produces electricity.

In order to reduce emissions while retaining high efficiencies, engineers in the 1960s and 1970s began examining ways to alter the coal combustion process. Two new categories of advanced technology have resulted: (1) fluidized bed combustors; and (2) advanced slagging combustors.

3.2.2.1 Fluidized Bed Combustors

In a fluidized bed combustor, rather than blowing a cloud of tiny coal particles into the combustor, crushed coal is mixed with limestone suspended on jets of air. This bed of coal and limestone actually floats inside the boiler, tumbling in a manner that resembles a boiling liquid, hence the name fluidized. As the coal burns, sulphur is released and the limestone acts like a chemical sponge capturing the sulphur before it escapes the boiler. More than 95 percent of the sulphur released from coal can be caught in this manner. The sulphur laden limestone forms a dry waste product. Some of the solid waste is removed with the bed ash through the bottom of the boiler. Smaller ash particles, or fly ash, are carried out of the boiler and captured with dust collectors. Because the tumbling motion of the coal enhances the burning process, combustion temperatures can be held around 1400 to 1600°F, or almost half the temperature of a conventional boiler. This is below the threshold where nitrogen pollutants form. Thus fluidized combustors can meet both SO_2 and NO_X standards without any additional pollution control equipment.[5]

Two types of fluidized bed combustion exist. One is called atmospheric fluidized bed (AFB) combustion (Figure 3.2) because the process operates at normal atmospheric pressures; the other is called pressurized fluidized bed (PFB) combustion because the pressures inside the boiler are elevated six to sixteen times higher than normal atmospheric pressure.

These systems have many common advantages over conventional boilers, including:

- the ability to control sulphur emissions without the need for coal cleaning upstream, or flue gas scrubbing systems downstream of the boiler;
- dry solid wastes, which typically require no special handling, can be disposed of in a manner similar to the way pulverized coal (PC) plant solid waste is disposed of. High concentrations of calcium oxide in the AFB ash can cause high pH levels that may require special handling;
- lower combustion temperatures, reducing the production of thermal NO_X emissions;

rate of heat transfer higher than in PC systems, thus reducing the total heat transfer surface area required; and

the opportunity to burn a broad spectrum of fuels, including coal, clean refuse, and other previously disposed of materials because of the turbulent nature of the fluidized bed.[6]

Bubbling-Bed AFB Power Plant

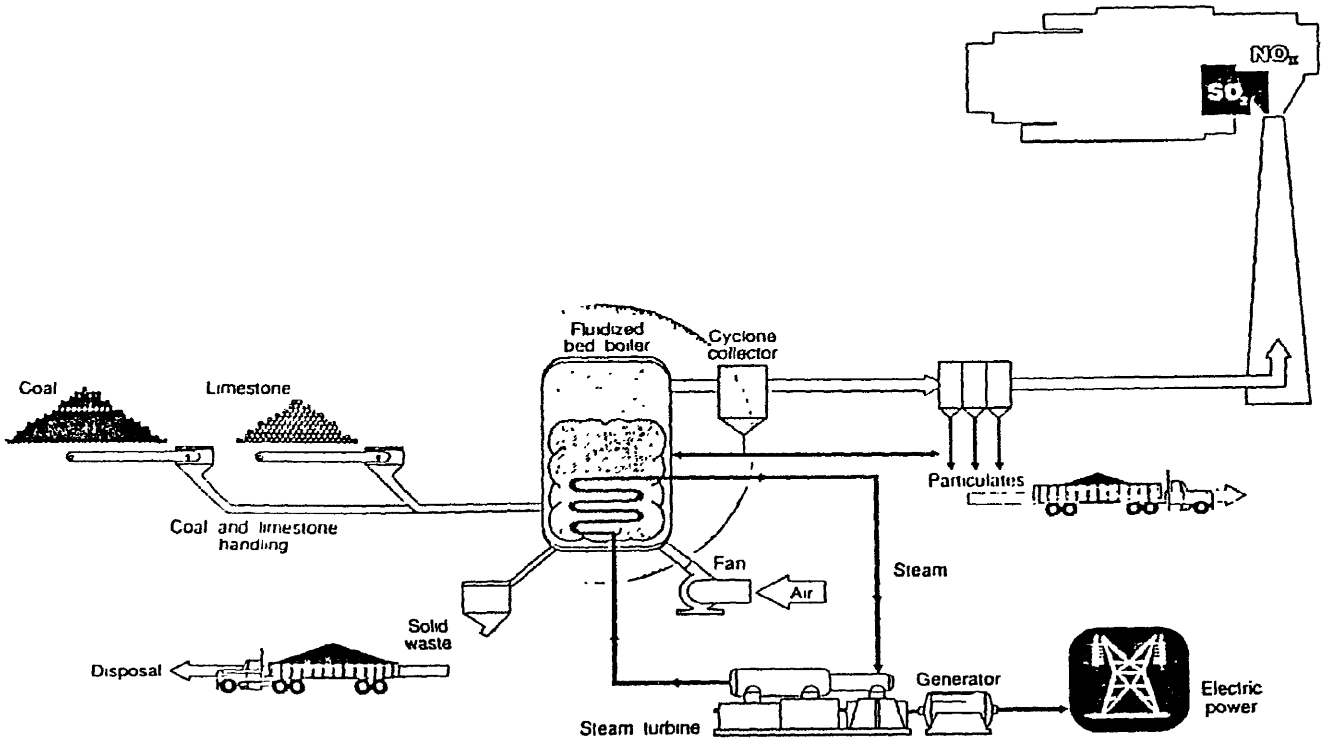
Bubbling bed AFB systems have been in use for over half a century. Although recent attention has been directed to circulating systems, bubbling bed power plants are still a viable power generation technology, and many believe they are more easily expanded to large utility-size power generation facilities.

Circulating Bed AFB Power Plant

Over the past five years, circulating bed AFB systems appear to be the preferred choice for industrial to small, utility-size power plants. Most units are less than 100 MW, and the largest is 165 MW. The higher velocities in CFBs allow for a smaller furnace plan area and therefore more compact design. More vigorous mixing of the gas and solids can lead to improved carbon burnup and calcium utilization. CFBs do not use in-bed tubes, thus eliminating the potential source of tube erosion/corrosion problems encountered in bubbling bed systems, but the dust-laden flue gas has caused considerable wear to insulating materials in the boiler and in the cyclones, and dust flowing down the walls has caused considerable wear, specially at the interface where the bottom refractory begins.[7]

The advantages of AFB over traditional PC technology are reduced emissions and increased tolerance to a wide range of low quality fuels. PC plants tend to break down when the ash in low quality fuels melts and clogs the boiler machinery. AFB plants have reported successful burning of fuels with ash contents of from 4 to 40 percent, and AFB can also burn rice husks and other agricultural wastes.[8]

Even though efficiency is not improved in an AFBC, the ability to burn lower quality fuels with less environmental impact makes this technology an attractive candidate for use in developing countries and Eastern Europe. Atmospheric fluidized bed combustion technology power plants are, however, not effective for reducing carbon dioxide emissions from coal combustion.



SO_2 REDUCTION	NO_x REDUCTION	EFFICIENCY	NEW PLANT CAPITAL COST	NEW PLANT ELECTRICITY COST	REPOWERED PLANT CAPITAL COST	REPOWERED PLANT INCREMENTAL ELECTRICITY COST	REPOWERED PLANT POWER OUTPUT	LIFE EXTENSION
90%	70%	35-36%	$1,200-1,400 PER KW	50-60 MILLS/KWH	$700-900 PER KW	12-17 MILLS/KWH	0-15% INCREASE	25-30 YEARS

SOURCE: Clean Coal Technology The New Era United States Department of Energy January 1991 DOE/EF-021 7P.

PFB combustion

PFB follows the same principle as AFB except that the boiler operates under pressure so the increased energy of the exit gases can drive both a gas turbine and a steam turbine (combined cycle), potentially boosting generating efficiency to over 40 percent. The relatively small size of PFB units is well suited to space-constrained sites and modular construction. Three commercial demonstration units, each of about 70-80 MWe capacity, are being constructed at utility sites in Sweden, Spain and the United States, each repowering an existing plant. An important issue for PFB is hot gas clean up, which is needed if the combined cycle is to realize its full potential for improving generating efficiency. Research efforts are in progress to clean the 1500 °F gases exiting the boiler without cooling them, so that they can drive a gas turbine directly. Various techniques are being tried, such as filtering with ceramic candles, ceramic cross-flow filters, and granular beds.[9]

Countering the potential advantages, the PFB has more serious technical obstacles to overcome and is less well developed than the AFB. For example, the corrosion of gas turbine blades is a primary concern for combined cycle PFBs. In addition, fuel and sorbent feed control may be difficult. It is unlikely that more than a few PFB commercial units will be completed and operating before the end of the century, although the long-term potential of this technology appears quite promising.[10]

AFB is now an established technology for industrial boilers (10 to 25 MW). It is being demonstrated at utility boiler size (75 to 350 MW) in a number of demonstrations in the U.S. and abroad. In Europe and the U.S., about 300 atmospheric fluidized bed units supply heat to industrial processes, municipalities, oil producers for thermal recovery processes, and farms for hay drying. AFB technology owners claim to have conceptual designs available for both bubbling and circulating systems in the 250 to 300 MW size range. CFB design of this magnitude would require multiple combustion chambers located side by side. Because they are almost mature technologies, it is not likely that either AFB system will experience any significant reduction in either manufacturing or construction costs, except whatever normal benefits may arise from economies of scale when larger systems are available. PFB systems, however, are still experiencing a steep learning curve, and operations to date indicate that several of the solids handling systems may lend themselves to simplification in future installations. Preliminary operating data also shows that sulphur capture may be better than some pilot plant data have indicated, which would result in a decline in both capital and operating costs.[11]

3.2.2.2 Advanced Combustors

Advances have also been made in new coal burning technologies based primarily on the cyclone combustor concept. In a cyclone combustor, coal is burned in a separate chamber outside the furnace cavity. The hot

combustion gases then pass into the boiler where the actual heat exchange takes place. The advantage of a cyclone combustor is that the ash is kept out of the furnace where it could collect on boiler tubes and lower the heat transfer efficiency. To keep ash from being blown into the furnace, the combustion temperature is kept so hot that mineral impurities melt and form slag, hence the name slagging combustors. A vortex of air (the cyclone) forces the slag to the outer walls of the combustor where waste can be removed.[12]

Unfortunately, the high temperature needed to melt the impurities is also a serious shortcoming, as unacceptable levels of NO_X are produced. Results to date from the U.S. Clean Coal Technology program show that by positioning air injection ports so that coal is burned in stages, NO_X emissions can be reduced by 50 to 75 percent. Injecting limestone into the combustion chamber can also reduce sulphur emissions by 50 to 90 percent.

3.2.2.3 Nitrogen Oxide (NO_X) Controls

Most NO_X controls work by preventing formation of the pollutant inside the furnace, although post-combustion NO_X scrubbers have been tested more recently. To control NO_X emission, plant engineers can modify the combustion process to lower flame temperature, or they can adjust the fuel mix so that only enough oxygen is present to support combustion and not enough to combine with nitrogen to form NO_X. Low-NO_X burners, for example, reduce NO_X emissions by delaying the mixing of fuel and air in the burner zone. By keeping the primary combustion zone deficient in oxygen, NO_X formation can be cut by about 50 percent. In other techniques, air ports are added in the furnace wall above the top row of burners to create a fuel-rich, low NO_X combustion zone. While these techniques require less hardware changes than low-NO_X burners, they only reduce NO_X formation by 15-30 percent.

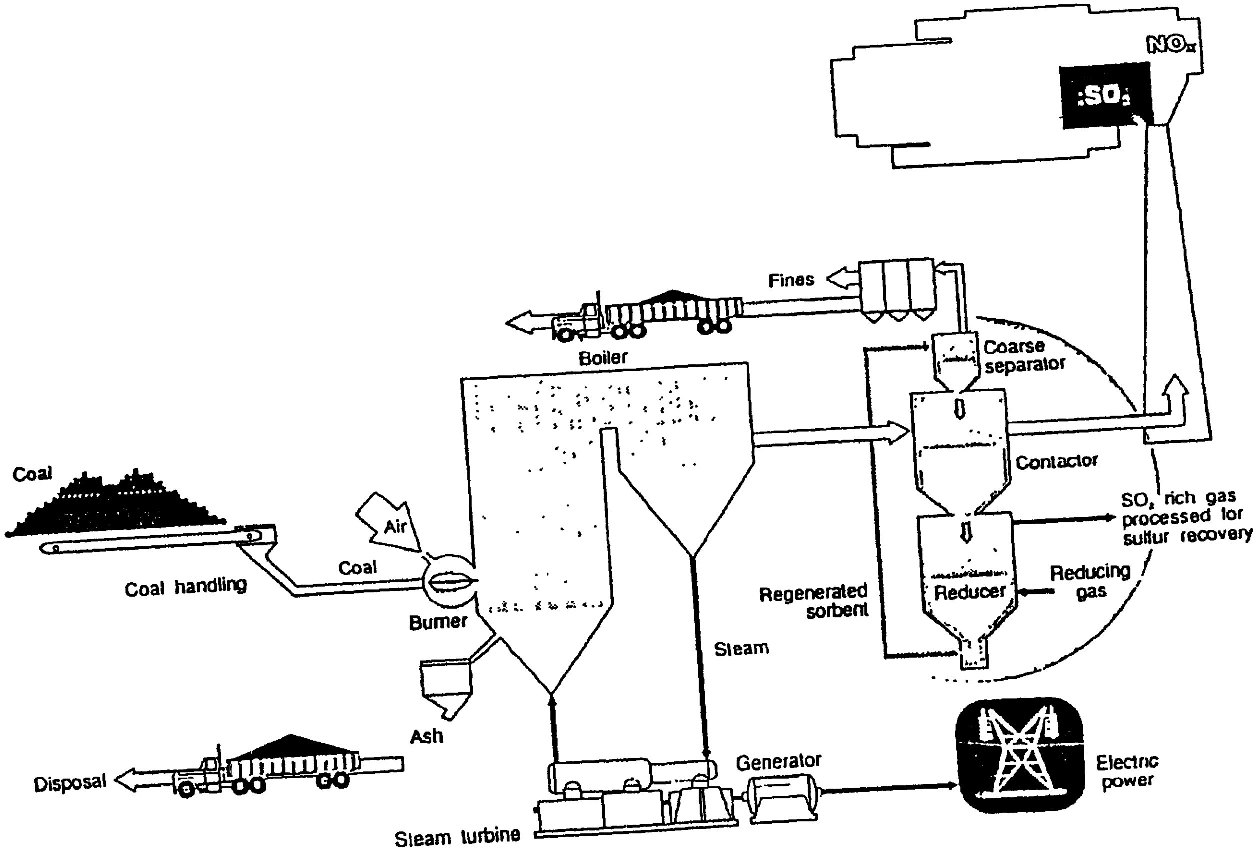
<u>Natural Gas Reburning</u>

A variation of NO_X control is natural gas reburning. A small amount of natural gas (10-20 percent of total fuel input) is injected above the normal combustion zone to form an oxygen-deficient zone. Coal is fired in the lower regions of the boiler to provide 80-90 percent of the total heat released. NO_X emissions from a gas reburning system are expected to be about 40 percent less than those from a unit firing solely coal. Other reburning concepts use coal instead of natural gas.[13]

3.2.3 Post-Combustion Cleaning

Until the emergence of clean coal technologies, post-combustion cleaning using scrubbers was the principal method of meeting air quality standards. Although techniques are available that remove as much as 90 percent of sulphur pollutants from the flue gases, new methods for post-combustion cleaning offer significant improvements over today's wet and dry scrubbers (Figure 3.3).[14]

Figure 3.3
Advanced Post-Combustion Cleaning



SO₂ EMISSION	NOx REDUCTION	COMPARED WITH CONVENTIONAL TECHNOLOGY* PLANT EFFICIENCY	POWER OUTPUT	PLANT LIFE	INCREMENTAL ELECTRICITY COST	CAPITAL COST
90%	High	Decrease	Small Decrease	No Change	10-12 MILLS/KWH	$175-300 PER KW

* CONVENTIONAL COAL-FIRED ELECTRIC POWER PLANT

SOURCE: Clean Coal Technology The New Era United States Department of Energy January 1991 DOE/EF-021 7P.

3.2.3.1 Sulphur Dioxide (SO_2) Controls

Advanced post combustion SO_2 controls can be grouped according
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3.2.3.2 Nitrogen Oxide Controls

Recent innovations in treating flue gases make it possible to reduce NO_x in flue gases leaving the coal boiler, instead of modifying the boiler. The most extensively developed concept is selective catalytic reduction (SCR). This technique is now being applied commercially in Japan, is being tested in the Federal Republic of Germany, and has undergone small-scale tests in the U.S.. In an SCR system, ammonia is first mixed with flue gas and passed through a reaction chamber separate from the scrubber vessel. In the presence of a catalyst, NO_x is converted by ammonia to molecular nitrogen and water SCR systems are projected to reduce nitrogen emissions by 50-80 percent

Unfortunately, high sulphur coals present unique problems with SCR technology, as the same catalysts that help break down NO_x also encourage sulphur dioxide to change to sulphur trioxide, which in turn combines with ammonia to form solid and liquid sulphates which can cause corrosion and plugging of downstream components.[15]

3.2.4 Conversion

Techniques that convert coal into another fuel bypass the conventional combustion process altogether. In the most commonly envisioned systems, coal is first converted into a gaseous fuel; in other techniques, a liquid form of coal is made, while in still others, a combination of gases, liquids and solids is produced.

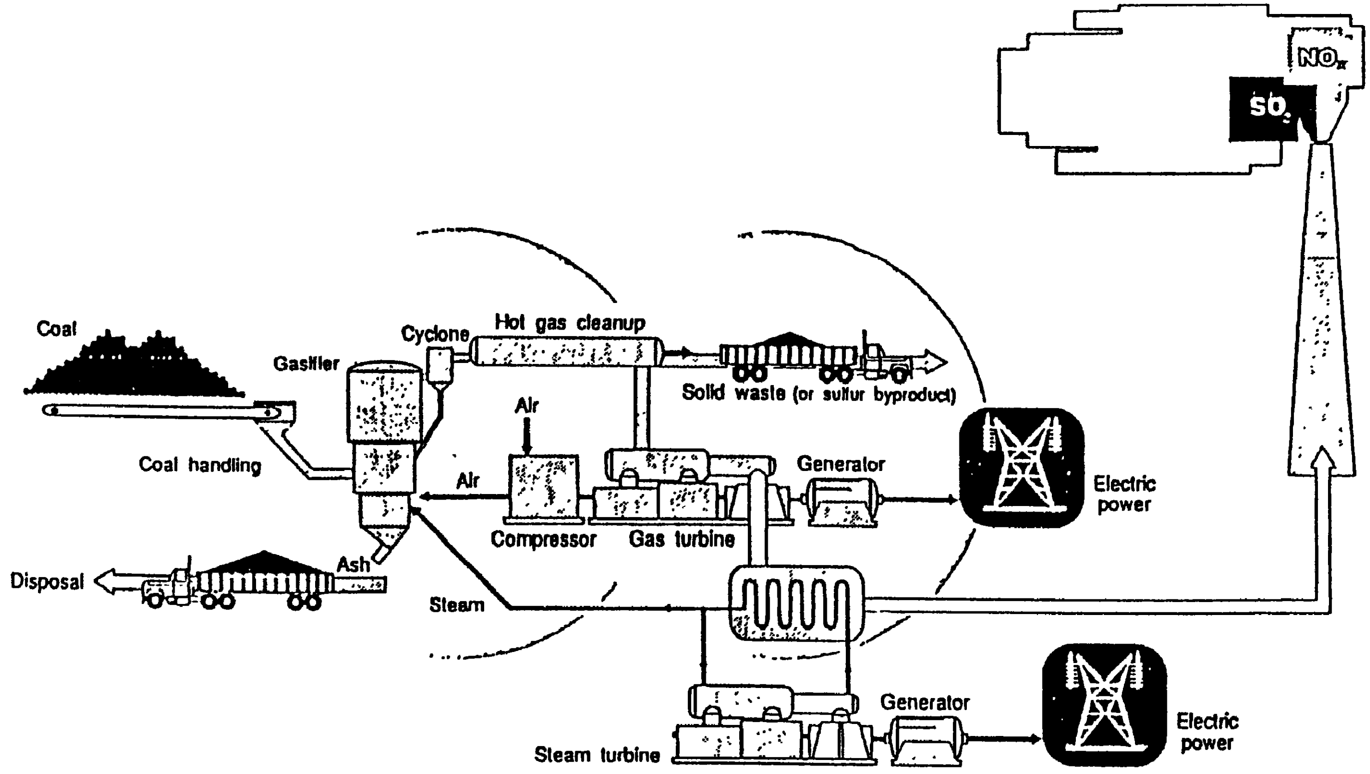
3.2.4.1 Gasification Combined Cycle

In the **integrated gasification combined cycle** (IGCC) process (Figure 3.4), coal is mixed with air and steam at high temperatures, which causes the coal to gasify to a mixture of hydrogen, carbon monoxide, and hydrogen sulphide, called syngas. The ash is separated and disposed of or used. The sulphur in the coal is converted into hydrogen sulphide, which eventually can be converted to elemental sulphur or some solid waste material. The hot exhaust gases that exit the combustion turbine generate steam, which can then drive a steam turbine to produce electricity The name combined cycle refers to the use of both gas-fueled combustion and steam turbines in the system. An IGCC system's major advantages are its very low rate of emissions and increased fuel efficiency. It also requires less water than a conventional coal-fired steam plant and, because of the modular design, construction time is shorter.[16] Integrated gasification combined cycle process efficiencies above 45 percent are now feasible (compared with 36-38 percent for the best conventional coal plants) and IGCC's environmental performance exceeds that of any other clean coal technology. Unlike end of the pipe control systems which mitigate a single pollutant, or fluidized bed combustion which suppresses several different pollutants at the plant level, IGCC slashes emissions virtually across the board

Power plants based on coal gasification offer three principal advantages. They can break the Rankine cycle barrier for efficiency. Their emissions are well below what is possible with the current generation of coal plants. And they offer unparalleled flexibility, since the coal gas can also be used as raw material for manufacturing a variety of important synthetic fuels and other products.

High efficiency is achieved by burning the coal gas in a combustion turbine and then using a steam bottoming cycle to recover low-level heat from both the gas turbine exhaust and the gasification process itself. Sulphur can be recovered chemically from the coal gas in elemental form, which can then be sold. Formation of nitrogen oxides is inhibited during combustion by saturating the coal gas with water vapour to reduce flame temperature The volume of solid waste produced by a gasification-based plant is less than half that of a conventional coal plant with scrubbers, and the product is an inert slag that can be used as a construction material. IGCC technology is also a very attractive candidate to burn high ash coals, such as those found in India.[17]

Figure 3.4
Gasification Combined Cycle



SO_2 REDUCTION	NO_x REDUCTION	EFFICIENCY	NEW PLANT CAPITAL COST	NEW PLANT ELECTRICITY COST	REPOWERED PLANT CAPITAL COST	REPOWERED PLANT INCREMENTAL ELECTRICITY COST	REPOWERED PLANT POWER OUTPUT	REPOWERED PLANT LIFE EXTENSION
95-99%	>90%	40-42%	$1,100-1,400 PER KW	45-50 MILLS/KWH	$950-1,200 PER KW	0-4 MILLS/KWH	100-200% INCREASE	25-30 YEARS

One of the advantages of IGCC systems is that they can be built in 100-150 MWe modules. This flexibility in capacity expansion means that power can be increased as demand warrants, thus reducing the problem of overbuilding capacity. Also, this modular design allows for a significant portion of the IGCC unit to be shop fabricated resulting in standardized design, better manufacturing control, and lower labour rates, yielding lower unit costs than on-site fabrication.[18]

The ultimate advantage of coal gasification is that its flexibility extends not only to generation of electric power but to coproduction of many commercial chemicals, in an integrated energy facility. Heat from the gasification process can be used directly in industrial processes or for district heating. Gasification of coal produces a mixture of hydrogen and carbon monoxide which can be reacted in the presence of a catalyst to form methanol, a raw material for making numerous industrial chemicals. Commercial processes are available, for example, to convert methanol into acetic acid, formaldehyde, and proteins. It can also be used directly as a fuel for turbines or automobiles. Alternatively, the hydrogen and carbon monoxide can be used to form gasoline or the hydrogen can be separated and reacted with nitrogen to form ammonia for fertilizer. Coal ash could find use in highways and railroads, cement and concrete, and as a source of high value trace metals.[19]

Commercializing IGCC technology does not require further technology development. Fuel prices rather than technology limit commercial operation. However, further developments promise greater efficiency and/or lower investment costs, both improving the technology's performance. The following improvements are under development:

- better solids handling for the coal feed into the pressurized gasifier vessels, to lower maintenance time and cost;
- hot gas cleanup to simplify gas production plants and lower investment cost (this also includes a potential for improved efficiency);
- higher gas turbine firing temperature to raise efficiency;
- heat exchangers for improved steam condition for greater efficiency; and
- higher levels of plant integration.

Table 3.4 presents a summary of net power plant efficiencies, plant CO_2 emissions, and CO_2 reduction potentials (relative to the reference PC plant) for a number of emerging coal-based combined cycle schemes including integrated gasification combined cycles (IGCC), pressurized fluidized bed combustion (PFBC), hybrid gasification cycles, and pressurized pulverized coal or direct coal-fired turbine cycles (DCFT). The net power plant efficiency of 43 percent (LHV) for an IGCC plant is based on the use of a high temperature

entrained bed gasifier with low temperature cleaning of the fuel gas. With cooling of the fuel gas, a significant fraction of the sensible heat in the gas leaving the coal gasifier by-passes the gas turbine cycle. The development and use of high temperature gas cleaning schemes would further increase the overall IGCC power plant efficiency.

PFBC combined cycle power plants rely on the direct expansion of a hot pressurized flue gas through a gas turbine. In-bed heat extraction and waste heat recovery from the gas turbine exhaust provides higher quality steam conditions and higher steam cycle efficiencies relative to gasification processes. However, due to a lower gas turbine inlet temperature of 700-900 °F (c f. 2000-2400 °F inlet temperature for IGCC) the overall efficiency is marginally lower at 42 percent. With CO_2 emissions from limestone used for in-bed desulphurisation, the total plant emission at 226.7 g C/kWhe is incrementally higher than that for a comparable IGCC process.

Hybrid PFBC schemes which rely on the partial gasification of coal in a topping cycle in addition to the generation of a pressurized gas from residual char combustion have also been proposed. With burning of the fuel gas from coal gasification, higher gas turbine inlet temperatures and combined cycle efficiencies are possible. Estimates suggest that net power plant efficiencies as high as 48-49 percent are possible and these higher efficiencies reduce the power plant CO_2 emissions by 23-25 percent compared to the reference PC power plant.[20]

3.2.4.2 World Status of Gasification Technologies

Moving Bed Gasification

A total of 170 commercially operating Lurgi gasifiers are working in South Africa, Czechoslovakia, Germany and the United States. The most common gasifiers are 3.7 metres in diameter and 10 metres in height gasifying around 900 tonnes of coal per day at pressures up to 30 kg/cm^2. The product gas leaves the gasifier at a temperature of 400 to 600 °C. This type of gasifier requires non-swelling, high reactivity coals which are coarser than 6 mm Coal fines up to ten percent of feed can be charged. Drying and crushing or grinding of coal is not required. The gas generated has high methane content with a methane to carbon monoxide ratio of 0.5 while the hydrogen to carbon monoxide ratio is also high, around two. This makes the gas ideally suitable for synthetic natural gas. Due to the low overall gasification efficiency (78 percent) with low ash coal, it is only marginally superior to pulverized coal power plants.

Table 5.4

Summary of CO_2 Abatement Measures For Power Generation

Technology	Steam Conditions	Net Power Station Efficiency (LHV) (%)	CO_2 Emissions (gC/kWhe)	CO_2 Reduction (%)
Conventional:				
PC + FGD	Subcritical	35	262.1	0
AFBC	Subcritical	37	257	1.95
PC + FGD	Supercritical (25 MPa)	45.3	208.1	20
PC + FGD	Supercritical (30 MPa)	47.5	198.7	31.9
PC - Natural Gas Co-firing	Subcritical	36-37.5	233.3-242.1	7.4-11
PC Design - Coal Oil Mixture	Subcritical	35	251.2	4.2
PC CO_2 Flue Recycle	Subcritical	27.6-28.6	-	(100)[a]
PC Design H_2 Combustion	Subcritical	8.4	-	(100)[a]
Combined Cycles:				
IGCC	Subcritical	43	212.7	18.9
IGCC	Subcritical	29.9-38.7	-	(90)[a]
PFBC	Subcritical	42	226.7	13.5
PFBC - Gasification Cycle	Supercritical (25 MPa)	48-49	195.6-199.5	23.9-25.4
Pressurized Pulverized Coal	Subcritical	48	194.2	26

(Continued On Next Page)

Table 3.4 (Continued)

Technology	Steam Conditions	Net Power Station Efficiency (LHV) (%)	CO_2 Emissions (gC/kWhe)	CO_2 Reduction (%)
PC - Natural Gas + FGD, deNO	Subcritical	40	202.1	22.1
PC - Natural Gas + FGD, deNO	Superciritcal (30 MPa)	49	166.1	36.6
MHD	Subcritical	40-45[b]	192.5-216.5	17-27
Fuel Cells	Subcritical	45-48[b]	147.1-192.5	26-44
Cogeneration:				
Combined Heat and Power (CHP)	Subcritical	77-84	108.9-118.5	54-59

[a]Indicates CO_2 disposal.
[b]HHV.

SOURCE: I.M. Smith and K.V. Thambimuthu, *Greenhouse Gas Emissions and the Role of Coal*, IEA Coal Research, U.K.

British Gas, in collaboration with Lurgi, have improved the moving bed gasifiers to remove some of the deficiencies of the original design. A 2.43 metre diameter gasifier with a capacity of 600 tonnes of coal per day is operating in Scotland, UK. The product gas is fed to a gas turbine to generate power. The modified process allows liquid slag formation. The gasifier has a high overall gasifier efficiency of 91 percent; the product gas contains less methane (four percent) with a lower hydrogen to carbon monoxide ratio of 0.57 percent.

Fluidized Bed Gasification

A 35 tonnes/day Process Development Unit (PDU) using oxygen/ steam was operated till 1990 in the United States by KRW. Another 30 tonnes/day pilot plant was set up to carry out tests in the U.S. by the Institute of Gas Technology (IGT). A wide range of coals have been tested in these two units.

A KRW gasifier is a pressurized (20 kg/cm^2) fluidized bed with a hot ash agglomerating zone which is hotter than the main fluidized bed. The feed coal is crushed to minus 6 mm, dried, mixed with limestone and pressurized in lock hoppers. This enables 85-95 percent desulphurization. The oxidants used are air, oxygen or enriched air. The moisture content of the coal has to be reduced to below five percent. The methane to CO ratio in product gas is 0.13 while the H_2/CO is around 0.74. The overall gasification efficiency is around 88 percent.

The IGT gasification process is similar to the KRW process in many respects and has been operated up to 30 kg/cm^2 pressure. The resulting CH_4/CO ratio is 0.15 while the H_2/CO ratio is 1.1.

The High Temperature Winkler fluidized bed process is in operation in Germany, gasifying 720 tonnes/day of lignite. In this process, crushed lignite (<6 mm size) containing up to 20 percent moisture is screw conveyed into a gasifier, using oxygen and steam as oxidants. The bed temperature is maintained at 800-1000 °C under a pressure of 10 kg/cm^2. Secondary oxidants are introduced above the bed to maximize carbon conversion. The methane/CO ratio in product gas is 0.09 while H_2/CO ratio is 0.79.

The U.S. Department of Energy has recently selected two clean coal demonstration projects. An IGCC plant is proposed to be built in Western Nevada, U.S.A., based on the KRW process. Also a consortium including IGT will conduct a demonstration project in Virginia, U.S.A. to deliver 107 MW of power to feed an existing electric grid.

Dry Entrained Gasification

Since 1987, Shell International Petroleum has been operating a 250 tonnes/day coal gasification demonstration plant in Texas, U.S.A. The process uses dry coal (less than three percent moisture) pulverized to below 90 microns and pressurized in lock hoppers. The gasifier operates at 30-40 kg/cm^2 pressure and 1400-1600 °C temperature. The ash in the coal is removed as molten slag and quenched in water. There is practically no methane production while the H_2/CO ratio is 0.5. The overall gasification efficiency is around 96 percent with low ash coals. A 250 MW commercial IGCC plant is under construction in the Netherlands. Krupp-Koppers in Germany have also developed a dry entrained gasification process. A 150 tonnes/day demonstration plant was operated at 30 kg/cm^2 using dry finely ground coal. The gasifier operated at high temperatures with product gas at 1300-1600 °C.

Slurry Entrained Gasification

For moisture bearing coal, drying to two percent moisture as required in the dry entrained gasification leads to substantial energy consumption, besides the need for a high pressure pneumatic transport and lock hopper system required to handle very fine coal. These problems are avoided by making a slurry of coal with water and feeding the slurry directly to the gasifiers with high pressure pumps. Two processes have been developed and are operating on commercial scale.

Dow Chemicals is operating a 2200 tonnes/day gasifier in the U.S. using lignite for producing 160 MW electric power. The gasifier is operated at 22 kg/cm^2. The product gases are cleaned in cyclones and the thermal energy recovered in steam boilers and steam super heaters. The overall gasification efficiency with low ash lignite is 93 percent.

Texaco has installed several slurry based gasifiers in the U.S., Germany and Japan. In this process, coal is wet ground to 200 mesh size and slurried with water. The gasifier operates at a pressure of 40 kg/cm^2. The gasification temperature is 1400-1600 °C and most of the thermal heat is transferred in a radiant cooler where high pressure steam is generated. The process is suitable for low ash coals and lignites. The product gas contains traces of methane with H_2/CO ratio of 0.78. The overall process efficiency is 93 percent with radiant cooling and 85 percent with quench cooling.

3.2.5 Magnetohydrodynamics (MHD) and Fuel Cells

Further gains in efficiency can be obtained by replacing the combustion turbine with a fuel cell. In a fuel cell, electrodes act as catalysts for the oxidation of a continuous stream of hydrogen-rich gas, releasing and absorbing electrons in the process. The molten carbonate fuel cell (MCFC) is now approaching the utility demonstration stage. Although the first demonstration unit will be fuelled with natural gas, there are plans to test the

fuel cell with coal gas as well. Future improvements could lead to a coal-to-electricity efficiency of about 60 percent, compared with 37 percent for pulverized coal technology. Futuristic schemes such as coal-fired MHD and MCFC and solid oxide fuel cells (SOFC) offer the potential of achieving even higher power generation efficiencies. Table 3.1 shows that these high efficiencies could potentially reduce CO_2 emissions by 17-27 and 24-44 percent respectively, for coal-fired MHD and fuel cell based systems. In short, there are many options for the abatement of emissions from coal use in power generation.[21]

Taken as a whole, the MCFC combined with coal gasification technology is the cleanest, most efficient coal plant system now conceivable. CCTs can be used for both newly constructed power plants and to repower existing power plants. In repowering or rehabilitation, the combustion system is replaced with one of the new technologies. Other new components, such as a combined cycle unit, may also be installed. The result is a renovated plant with efficient performance.[22]

3.2.6 Retrofit and Repowering

Retrofit technologies generally are pollution control devices that can be installed on older plants without making major design changes in the plant design. Some retrofit technologies offer a means of reducing sulphur emissions by 50 to 70 percent at a far less cost than a scrubber. Retrofit technologies include:

- precombustion coal cleaning;
- limestone injection multistage burners;
- in-duct sorbent injection;
- gas reburning;
- advanced slagging combustors; and
- advanced scrubbers.

Many CCTs offer the option of repowering older power plants, not only reducing their emissions but extending their lifetime by 20 to 30 years. Because of their higher efficiencies, the new technologies can boost an older plant's electrical output by 40 percent to 200 percent. For some installations, the effect would be the equivalent of two or more power plants at the original site, with sulphur emissions as much as 99 percent lower and NO_X emissions 40 percent lower than the older plant. Repowering concepts may also become the technologies of choice for future, new plant construction.

Repowering technologies in general replace a major portion of an existing plant (such as the boiler) with new power generating equipment while retaining other portions of the plant (such as the steam generating equipment) Repowering comes into play when existing coal fired plants reach the end of

their useful lives--typically around 25 to 40 years after they are built--and a utility must decide whether to retire or rebuild the facility. Repowering also becomes attractive when power generation needs have increased and a utility wants to avoid the problems of finding and obtaining approval for a new site. Many repowering concepts also rely on standardized, shop-fabricated components. This minimizes the costly, customized, on-site construction typical for conventional technologies. Several examples of repowering technologies are:

- AFBCs
- pressurized fluidized bed combustor combined cycle
- IGCC.

3.3 Canadian Experience with CCTs[23]

Canadian thermal coals, ranging from lignite to low-volatile bituminous, are being burned successfully for heat and electricity by both domestic and foreign utilities. Development of technology to reduce operating costs, improve equipment availability, increase fuel flexibility, and control emissions is on-going and several novel installations are being commissioned or are being seriously considered.

Generally the sulphur content of the lower rank and low-volatile bituminous coals varies from 0.2 to 0.8 percent, whereas that of the high-volatile bituminous coals varies from one to three percent with one mine running as high as eight percent. All of these coals have nitrogen contents ranging from 0 5 to 2.0 percent with 1.0 percent being an average value. Most of the thermal coal mined in Canada is used for electricity generation.

All coal-fired utility boilers in Canada are pulverized-fired with wall or tangential burner arrays mounted in dry bottom furnaces. Unit sizes range from 25 to 500 MW and plant generating capacities range from 50 to 4300 MW. Emissions from existing units are monitored by provincial authorities whereas new sources are designed to comply with federal guidelines that currently specify 258 ng/J for SO_2, 258 ng/J for NO_X, and 43 ng/J for particulate matter

As a signatory to the Convention on Global Warming, Canada is committed to limiting national CO_2 emissions to 1990 levels. Consequently, reliable cost-effective technology that maximizes the conversion of coal to electricity is a priority consideration in the selection of all new coal-fired generators.

3.3.1 Pulverized Coal Technology

A number of innovative clean coal technologies are being implemented or are planned for future installation by Canadian utilities. These

include a variety of systems for retrofit to existing units and emerging processes for new units. Some are described below.

3.3.1.1 Retrofit Projects

To meet provincial targets for acid gas emissions several operational units have been modified or are being studied for retrofitting of selected abatement technologies. In Western Canada, NO_X targets for existing units burning low-sulphur lignites and subbituminous coals are being met by reducing and biasing the combustion air. At Poplar River Generating Station, low cost changes to a 300 MWe lignite-fired boiler with tangential burners resulted in NO_X reductions of 20 percent from about 260 ng/J to 195 ng/J at full load; urea injection decreased NO_X levels to about 150 ng/J with little or no NO_2 production. Additional trials on this unit with a system that combines in-furnace limestone injection with post-furnace humidification successfully reduced SO_2 emissions from a 150 MWe slipstream by 50 percent to meet federal guidelines.

A recent project aimed at suppressing NO_X emissions in subbituminous coal-fired boilers with tangential burners has demonstrated that federal guidelines can be met with very inexpensive hardware changes. The key to consistent performance was the development of an expert system that monitors critical operating parameters including boiler load, burner tilt and combustion air distribution in conjunction with O_2, CO and NO_X levels in flue gas. These trials indicated that the NO_X avoidance cost with this system, at approximately $50/tonne, is substantially lower than alternative retrofit technologies such as selective catalytic reduction or low NO_X burners. The cost of retrofitting this expert system is estimated at $1.25/kW.

3.3.1.2 New Units

Two new units, one rated at 300 MWe on lignite with opposed wall firing and one rated at 450 MWe on high-volatile bituminous coal with tangential firing, are now being commissioned. Both units incorporate low NO_X combustion and sulphur capture systems.

3.3.1.3 Industrial Boilers

A full scale demonstration of a slagging burner prototype in a steam generator for heavy oil recovery has been completed. In this system a pulverized mixture of coal and limestone is injected into an entrained flow reactor where partial gasification of the coal occurs. Combustion air staging is used to enhance a) char burnout in the combustor, b) sulphur capture by calcium species in the slag, c) conversion of fuel nitrogen to N_2, and d) flowability of slag at the burner exit. During field trials with a 0.3 sulphur subbituminous coal, NO_X and SO_2 emissions respectively were below 86 ng/J and 128 ng/J. Carbon burnout consistently exceeded 99 percent and ash removed as slag varied from 50 to 65 percent.

3.3.2 Fluidized Bed Technology

Canadian interest in fluidized bed combustion has been driven primarily by environmental concerns. FBC's potential to minimize both SO_2 and NO_x emissions make it attractive for Eastern Canada, where the only indigenous fuel available is coal, most of it containing from 3 to 10 percent sulphur. In Western Canada, possible applications are seen in using high-sulphur residues from heavy oil upgrading, and high-ash rejects from coal preparation plants.

To meet the challenge of utilizing indigenous coal in an environmentally acceptable manner the federal government sponsored a demonstration of fluidized bed combustion technology in a heating plant at Summerside, Prince Edward Island.

An extensive demonstration program was incorporated into the daily operation of the heating plant. Five bituminous coals were tested for boiler performance and emissions, at loads from 22 to 100 percent of maximum capacity rating. Sulphur content ranged from 4.1 to 11.3 percent and sulphur capture of 80 percent or more was achieved with Ca/S ratios of about 2:1 at low loads and 3:1 at high loads.

A small-scale electric utility FBC demonstration has been constructed at Chatham, New Brunswick. The objective of this venture was to establish the viability of circulating FBC technology for generating electricity from high sulphur-coal. A new boiler was constructed to repower an existing 22 MWe turbine. Circulating, instead of bubbling FBC technology, was selected in expectation of more efficient calcium utilization and more economic scale-up to the large units required by electric utilities.

Performance specifications:

Sulphur capture: 90 percent with fuel containing more than 258 ng/J of sulphur

NO_x emissions: maximum of 258 ng/J of fuel input

Particulate emissions: maximum of 43 ng/J of fuel input

The Chatham unit was occasionally employed to evaluate fuels or limestones for other agencies. At 22 MWe it is small enough that such work can be carried out at reasonable cost but large enough that results can be safely extrapolated to the +100 MWe blocks that are of interest to most utilities. One such program was carried out for Nova Scotia Power Incorporated where circulating FBC was being considered for a 150 MWe power station. Over one month the design coal, containing about 5 percent sulphur, was fired with five different limestones and varying Ca/S ratios. The limestone was premixed with the coal and 90 percent sulphur capture was achieved. The results of the test

program convinced Nova Scotia Power that circulating FBC was the appropriate technology for the their new power station, and were invaluable in preparing specifications.

In October 1989, Nova Scotia Power Incorporated signed contracts for a single 165 MWe circulating FBC unit. This was the outcome of a lengthy evaluation of how best to meet a provincial commitment to reduce annual SO_2 emissions while continuing to use high-sulphur indigenous coal. Pressurized FBC and IGCC were also considered but were deemed insufficiently established for commercial application. Pulverized firing with wet limestone scrubbers appeared to be marginally less costly and slightly more fuel-efficient. However, circulating FBC was selected because of lower waste disposal costs, better NO_X control and greater fuel flexibility.

The design coal is high-volatile bituminous with 12 to 20 percent ash, three to five percent sulphur and 0.2 to 0.4 percent chlorine.

The plant is expected to achieve 90 percent sulphur capture with a Ca/S ratio of about 2:1; NO_X is expected to be well below federal guidelines and particulates will be controlled by a baghouse having a design efficiency of 99.5 percent. The ultimate planned capacity at the Point Aconi generating station is 495 MWe. The additional capacity may be provide by two more circulating FBC units or emerging technology such as pressurized FBC or IGCC.

3.3.3 Integrated Gasification Combined Cycle

Coal gasification is a priority because utility companies regard IGCC technology as the most likely coal based technology to be used in future electricity generating plants. The desire to minimize emissions have led to two thorough evaluations of IGCC technology. The first focused on Western Canada with lignite and subbituminous coals as fuels of primary interest, and a high-quality western bituminous coal as an alternative fuel. Three gasifiers and three gas turbine models were evaluated for a single train plant having a net output of about 250 MWe. Major conclusions are given below.

- No technical barriers exist, although the gasifier is likely to be the highest risk item.
- With low cost fuel, only moderate integration of the gasification and steam-raising cycles is economically justifiable.
- Thermal efficiencies slightly in excess of 40 percent are achievable with low-rank coals, resulting in CO_2 emissions 15 to 20 percent lower than a pulverized-fired plant of equivalent output.

- Low emissions of NO_x and very low emissions of SO_2 and particulates can be achieved.
- Special provisions primarily in solids handling and sulphur recovery are necessary to achieve 84 percent availability.
- The bituminous coal offered better efficiency and lower costs than the low-rank coals.
- Capital and operating costs are higher for IGCC than for conventional technology.

The second study focussed on Eastern Canada and evaluated four gasifiers using three high-sulphur bituminous coals. Target conditions were 41 percent efficiency and 85 percent availability. It was found that the former could be met or exceeded by all the gasifiers, but the latter would require redundant systems in some areas. Sulphur capture of 99 percent seems achievable with unit capacities ranging from 165 to 292 MWe. Table 3.5 shows that CFBC has a substantial advantage in unit capital cost, but IGCC has the best efficiency and the most favourable operating and maintenance costs. Based on these studies any application of IGCC in Canada is likely to be driven by environmental rather than economic considerations.

Table 3.5

Cost Comparison of Three Clean Coal Technologies

	CFBC	Pulverized Coal with FGD/SCR	IGCC
Cycle Efficiency %	34.8	36.7	41-42
Relative Capital cost per kW	1	1.03-1.19	1.15-1.42
Relative O & M cost per kWh	1	1.49	0.80-0.98

SOURCE: P. Pint, G.K. Lee and F.D. Friedrich, "Emerging Clean Coal Technologies in Canada", EMR/CANMET/Energy Research Laboratories Division Report, ERL 93-19 (OPJ), p. 16

Currently, the over-supply of electrical capacity, high capital costs and the abundance of low-cost natural gas in Alberta are slowing further IGCC development.[24]

3.4 Indian Efforts with CCTs

After an in-depth study of various gasification systems in the late 1970s, BHEL opted for inhouse development of a moving bed gasifier as a first phase of IGCC technology development and demonstration. A Combined Cycle Demonstration Plant (CCDP) of 6.2 MWe capacity comprising 4 MWe gas turbine and 2.2 MWe steam turbine was commissioned at Tiruchy in 1987. The coal gasification plant (150 tonnes/day capacity) consists of a moving bed gasifier coupled to a wet gas clean up system. The coal is gasified with steam

and air at a pressure of 10 atmospheres. The design coal feed rate is six tonnes per hour and generates 12,000 NM^3/h of coal gas; the calorific value of the fuel gas is about 1250 $Kcal/NM^3$. The carbon conversion achieved is in the order of 87 percent and gasification efficiency is the range of 75-80 percent.

The Indian Institute of Chemical Technology at Hyderabad has also tested a number of Indian coals in their 24 tonnes/day coal capacity Pressurized Moving Bed Gasifier. Two of the typical coals were also tested on a 150 tonnes/day Moving Bed Gasifier at BHEL, Tiruchy. The results have confirmed the validity for scaled up design of the adopted design methodology.

For development of Pressurized Fluidized Bed Gasification for Indian coals, a Process Equipment Development Unit (PEDU) has also been installed and is being operated at BHEL Corporate R&D Division, Hyderabad. The plant has a coal throughput capacity of 18 tonnes/day with air and steam as gasifying media. Coal of minus 6 mm is gasified by a mixture of air and steam at 900 °C and pressures up to 10 ata. The gas produced is water quenched and scrubbed to free it from particulates in the Venturi scrubber and demister. It is then burnt in the flare stack. The plant has been undergoing test trials and has logged around 1200 hours of operation so far.

In the field of low pressure, moving bed coal gasification with air/steam, considerable expertise exists in the country with Low Calorific Value (LCV) coal gas being used in industrial furnaces. Gasifiers up to three metre diameter are quite common. Recently, a 3.8 metre diameter gasifier has also been tested at Ennore TPS. The LCV gas produced has been used for low load coal flame stabilization in a pulverized coal-fired 60 MW boiler. While trails have shown positive results, the unit has been out of use for certain extraneous problems.

3.4.1 Economic Viability of Coal Gasification Technologies

Economic viability of coal gasification for power generation depends upon (i) the capital cost per unit of power produced, (ii) the cost of electricity generation, and (iii) environmental penalties. The following gasification processes are studied which have been demonstrated either at the commercial or pilot scale:

- dry entrained (DE) SHELL Gasification;
- slurry entrained (SE) TEXACO Gasification;
- fluidized bed (FB) Gasification; and
- moving bed (MB) Gasification.

The design coal is a non-coking, unwashed, run-of-mine coal from the Dakra seam. The coal, on as received basis, has 38.8 percent mineral matter, 8 percent moisture, a heating value of about 4000 kcal/kg, and an ash fusion temperature (fluid, under reducing atmosphere) of more than 1500 °C.

It represents the typical coal feedstock which would be available for future power generation in India. A conceptual design was prepared for a mine mouth IGCC plant located in Eastern India. The plant is designed with a minimum 70 percent sulphur removal. The NO_X emission is based on 75 ppm corrected for 15 percent oxygen. The total net power produced from the IGCC plant is approximately 600 MW.

Shell, Texaco, and KRW provided the necessary gasification process packages and cost data for the first three cases. The moving bed is a self developed technology. The gasifiers are oxygen blown in the first two cases and air blown in the other two cases. For the moving bed process, data were obtained from a 24 tonnes/day pilot plant and a 150 tonnes/day combined cycle demonstration plant in India. In the latter case, the gas was cleaned and used in a combined cycle plant generating 4 MWe in a gas turbine and 2.2 MWe in a steam turbine. The air required for the gasification was drawn from the gas turbine and was boosted to the required pressure. The steam required for gasification was partly met by the steam produced in a heat recovery boiler by the gas turbine exhaust gases. The balance steam was supplied by the jacket boiler.

The experiments in moving bed gasifiers showed that high ash coal can be gasified with air-steam injection. The calorific value of the gas and the gas yield are such that it can be used in combined cycle power generation.

In the feasibility study, the U.S. process licensors and consultants familiar with IGCC power plants provided the basic data on the cost of major equipment, engineering and owner's cost for U.S. conditions. These were recalculated for Indian conditions for purchase and installation at the site in India. The capital cost takes into account labour rates, productivity, sales tax, customs duties, shipping costs, and the differential in cost of production in India *vis-a-vis* the United States.

For the moving bed, the capital costs were derived by upscaling the equipment design and calculating the cost through bill of material, itemized and other cost figures. Cost for the pulverized coal plant were arrived at on the basis of the estimates of 1000 MWe capacity Super Thermal Power plant The specific capital cost for the three IGCC plants is compared with the PC plant with FGD in Table 3.6.

The Shell dry entrained IGCC plant has the highest specific capital cost--56 percent higher than a PC plant with FGD--due to the high capital cost of the air separation unit and the gasifiers. On the other hand, moving bed and fluidized bed IGCC plants are marginally costlier than the PC + FGD plants by twelve and nine percent, respectively. The cost for the IGCC plants are expected to decrease in the future as more engineering experience is gained in building these plants.

The cost of generation of IGCC plants is shown along with that for a PC plant in the lower part of Table 3.6. The cost of generation is again high for the dry entrained IGCC due to the high fixed cost, which is partially due to the high specific capital cost of the plant. The moving bed and fluidized bed IGCC plants also have higher fixed cost compared to the PC + FCD. On the other hand, the fluidized bed IGCC has a lower variable cost, due to the lower coal consumption per kWh of power produced. The fluidized bed IGCC power generation is expected to be techno-economically competitive with the PC + FGD.

A substantial number of coal-fired thermal power plants (of 10-100 MW) installed in the 1960s and 1970s are operating at efficiencies in the range of 18-26 percent. This compares to plants installed in the latter part of the 1970s and the 1980s which operate at efficiencies ranging from 30-37 percent. In some of these older, small capacity plants, the boilers, auxiliaries, and control systems have outlived their safe operating life and became obsolete. But, some of the equipment (i.e., steam turbine, electric generator and transformers) is operating and could be used efficiently for many more years.

Based on the performance of the demonstration plant to be set up during the 8th plan period, commercial scale application of IGCC is proposed as follows:

- retrofitting of gasifiers in the older power plants of capacities ranging from 20-100 MW during the 9th plan period; and
- installation of new IGCC based power plants having module capacity of 300 MW during the 10th plan period.

3.4.2 Air Pollution Control Technologies for Thermal Power Stations

3.4.2.1 Particulate Matter

Stringent emission limits make necessary the use of highly efficient particulate collectors such as electrostatic precipitators (ESP) instead of the less efficient mechanical devices used in the older power plants. In India, ESP has been the dominant collector in power plants constructed after the mid-1970s. There are no fabric filter installations for coal fired utilities in India. The limitations of fabric filter include short life of filter media and subsequently high cost of replacement.

Table 3.6

Cost Comparison Between IGCC and PC Plants
(4th Q, 1989 pricing)

	(DE) Shell	(SE) Texaco	(FB) KRW	Moving Bed	PC Plant Without FGD	PC Plant With FGD
New Power Output (MW)	564.4	496.2	577.2	585.7	558.0	549.0
Total Capital Required (Rs.Cr.)	2 055	2 059	1 460	1 529	1 065	1 278
Unit Capital Rs/kW net	36 428	41 500	25 292	26 103	19 084	23 276
Relative Unit Capital	1.56	1.78	1.09	1.12	0.82	Base
Cost of Generation, Paise/kWh						
- 5500 h/y operation	148.0	170.2	103.8	115.5	86.7	102.2
- 6000 h/y operation	135.4	158.1	96.5	107.6	81.4	95.6
- 7000 h/y operation	188.8	139.2	85.0	95.3	73.0	85.4
- 7400 h/y operation	113.4	133.0	81.3	91.3	70.3	82.1
Relative Cost of Generation (based on 5500 h/y operation)	1.43	1.67	1.02	1.13	0.85	Base

SOURCE: Council of Scientific and Industrial Research, Feasibility Assessment of IGCC Power Generatic Technology for High Ash Coals, New Delhi, February 1992.

3.4.2.2 Sulphur Dioxide

The sulphur content of an average Indian coal is low and so sulphur dioxide emissions are not a problem in India and can reach high levels only due to clustering of thermal power plants. A representative 210 MW plant firing 0.265 percent sulphur North Karanpura coal (i.e., coal with 0.72 kg sulphur/million kcals) would produce 3584 tonnes/year of sulphur dioxide. This corresponds to an emission level of 1.23 g/m^3. No emission standards for SO_2 are mandated in India. Three methods, individually or in combination may be used to reduce SO_2 emissions. These are:

(a) use of tall stacks to increase atmospheric dispersion;
(b) flue-gas desulphurization; and
(c) desulphurization of fuel.

Tall Stack Dispersion

This control method is based on natural dispersion at high elevation so that ground level concentrations are acceptable at all times. This approach is recommended by the Central Pollution Control Board. The standard that has evolved for the stack height requirement for thermal power stations is given in Table 3.7. The benefit of using tall stacks for pollutant dispersion is that it does not rely on sulphur dioxide removal processes and/or fuel desulphurization methods, which involve high operating costs. When removal systems are added later, air quality will improve further. To a certain extent, a tall stack also acts as a safeguard against removal equipment breakdowns and adverse meteorological conditions in the future.

Table 3.7

Stack Height Regulations for Dispersion of Sulphur Dioxide

Boiler Size (MW)	Stack Height (m)
>500	275
200-500	200
<200	140

SOURCE: Central Pollution Control Board, New Delhi, 1979.

Flue Gas Desulphurization

Sulphur dioxide removal processes may be grouped according to two classification (1) throwaway or regenerative, and (2) wet or dry. Throwaway processes are those in which a solid waste product is formed which must be discarded. As a result, fresh chemicals also must be continually added. In the regenerative process, the chemistry is such that the removal agents can be continually regenerated in closed loop systems.

Conventional (wet) lime and limestone processes continue to be installed worldwide at thermal power plants. Currently, over 80 percent of the total FGD units installed and under construction fall under this category. The popularity of these systems is mainly due to the wide design and operating experience gained over the last two decades and the availability of cheap material.

Cost of an FGD system has been a major consideration in the evaluation of environmental impact versus socio-economic benefits of thermal power stations. A detailed cost comparison of the various FGD processes based on U.S. experience and adapted to Indian conditions is presented in Table 3.8. These processes have been sized for a 1050 MW (5 x 210 MW) plant burning North Karanpura coal. It is assumed that an SO_2 emission level of 0.5 g/m^3 has to be achieved after the FGD process. This corresponds to nearly 60 percent removal. For comparison, estimated costs for 90 percent removal (emission level of 0.125 g/m^3) are also shown. It may be of interest to note that a typical spray dryer system on a boiler using low sulphur coal in India would increase the cost of power generation by approximately Rs. 0.154/kWh to 0.300/kWh. As of March 1989, there is only one FGD installation in India for a power plant (at the Tata Electric Company's plant in Trombay). However, the Central Pollution Control Board stipulates that space should be provided for in the layout of power plants of capacities of 500 MW and above, so that FGD systems could be installed in the future, if necessary.

Table 3.8

Cost Comparison of FGD Processes for a 1050 MW TPS Burning North Karanpura Coal

Process	Capital Cost (million Rs.)		Operating Cost (million Rs.)		30-Year Levelized Cost (Rs./kWh)	
	60% removal	90% removal	60% removal	90% removal	60% removal	90% removal
A. Wet Throwaway Processes						
1. (a) Lime	3245	3550	365	560	0.154	0.198
(b) Limestone	3450	4165	375	520	0.162	0.207
(c) Dual Alkali	3650	4340	380	480	0.168	0.205
B. Wet Regenerative Process						
1. Magnesium Oxide	4590	6280	472	700	0.120	0.298
2. Welman-Lord	4550	6230	475	725	0.209	0.300

SOURCE: Tata Energy Research Institute, 1989

3.5 Conclusion

In India, coal-based thermal power generation will continue to grow to meet increasing power demand. Improved operating and maintenance practices would yield quick returns in terms of efficiency improvements.

Innovative technical opportunities now exist which could be used for modifications of existing conventional coal power plant to significantly improve their cost-effective environmental performance. Technologies which could be used on the fuel side include conventional coal washing which can result in efficiency increases in the power plant in the form of increased generation, less ash handling, etc., but higher fuel costs. Combustion modification processes such as stage burners, reburning, etc. could be introduced. Post-combustion clean up technologies include conventional and advanced flue gas scrubbing, but at substantially higher costs.

Technologies aimed at replacing a significant portion of the original plant to reduce emissions and often to increase capacity are as follows:

- integrated gasification combined cycle
- circulating fluidized bed combustion
- PFBC with combined cycle
- MCFC with combined cycle

Integrated technologies based on PFBC, coal gasification, and MCFC are environmentally better options with high efficiency and consequently with less carbon dioxide emissions. Large scale implementation of integrated technologies would result not only in reduction of SO_2 and NO_X but also lower CO_2 emissions.

Fluidized-bed combustors seem to be the best alternative to pulverized coal boilers in the medium term. FBCs cost as much as pulverized coal boilers, require less annual expenditure, are more efficient, and have lower specific emissions of both CO_2 and NO_X. They are, however, only presently available in capacities up to about 150 MW. There is an urgent need to immediately introduce 100 MW CFBCs at a number of stations in the country, so as to start gaining operating experience.

In the long term, IG-MCFC is potentially the most efficient advanced coal-to-electricity technology. However, it is still in the developmental stage and at least a decade away from demonstration level operation. As expected, the largest uncertainties, both with respect to overall efficiency and expected cost of electricity, are associated with this technology, the single-largest uncertainty being the capital cost of MCFC.

PFBCC technology is next, both in terms of efficiency and electricity cost. The uncertainties associated with PFBCC cost and efficiency parameters are less when compared with IG-MCFC systems, and the single largest uncertainty is the PFBC capital cost. This is primarily due to uncertainty in costs of gas cleanup devices which are capable of conditioning the PFBC flue gas to meet gas turbine inlet standards.

The IGCC system is the only advanced coal utilization technology which has already entered the commercial market. In the perspective of the

levels of technological and commercial development of these technologies, their efficiencies and costs of electricity generation, and the scarcity of financial resources in India, a long-term strategy for the introduction of these technologies into the Indian market is developed in the following.

In the short-term, IGCC systems should be installed in an increasing percentage of the added capacity and all retrofit/renovations of existing capacity. By the turn of the century, the share of IGCC systems might reach the 5000 MW mark. This will decrease the capital requirement of the thermal electricity program and create a work force trained in the operation of gas turbines and coal gasifiers. It will also add to the peaking electricity capacity in the country which is presently far short of the desired system optimum owing to delays in the addition of hydro-electric capacity. During this period, an intensive systems engineering effort should be launched so as to develop commercially viable PFBCC systems by 2000. A similar R & D effort --but with much larger funding--should be launched to develop commercially viable IG-MCFC system by the turn of the century.

In the medium time frame, the PFBCC system should be introduced into the market so that it constitutes at least 50 percent of all new capacity additions in the tenth plan. During this time frame, IGCC systems should maintain its share of new capacity additions. The IG-MCFC systems should start entering the market in the beginning of the 21st century. Gasifier operating experience of about ten years will be available by that time, but the entirely new MCFC technology will lead to a comparatively modest market entry.

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Chapter 4

COGENERATION

4.1 Introduction

Cogeneration is the simultaneous production of power, either electrical or mechanical, and useful[1] thermal energy from a single fuel source. A cogeneration system is an integration of the various components (energy conversion system, balance-of-plant systems, heat source, heat pump, etc.) into a total system which provides the electrical and thermal requirements of a specified industrial process.

Cogeneration technologies are typically divided into two basic categories according to whether electrical or thermal energy is produced first, termed topping and bottoming cycles. In the topping cycle, the primary fuel is used to produce electricity and the thermal energy exhausted is used for process heating. In the bottoming cycle system, the primary fuel is used to produce high temperature thermal energy. The hot exhaust steam is subsequently used to produce electrical energy through a waste heat boiler and turbine generator system. The specific components comprising a cogeneration plant will however, depend upon the industry, the energy conversion system, and the strategy picked for sizing the energy conversion system.

4.1.1 The Case for Cogeneration

The recent interest in cogeneration beyond the traditional mainstay of cogenerators, such as the forest product industry is due not only to the direct benefits to industry and institutional applications, but also the positive carry-over benefits to utilities and society at large. The opportunities for industry, utilities, and society are depicted in Figures 4.1, 4.2, and 4.3.

4.1.2 The Energy Conservation Potential-design Trade-off

To illustrate the material increase in efficiency afforded through cogeneration, it is instructive to compare the fuel use efficiencies of conventional electricity generation and cogeneration. As shown in Figure 4.4, approximately 50 percent of the heat is released through the cooling water in conventional electricity generation. Another 15 percent is released as waste heat from the fuel stack. This process then yields an overall fuel use efficiency of about 35 percent. With cogeneration, two-thirds of the fuel is used for process heat, 15 percent is used to generate electricity, and only 15 percent is lost, resulting in an overall energy efficiency of 80 to 85 percent.

Figure 4.1
Cogeneration Opportunities for Industry

REDUCE ENERGY COSTS	The cost of the incremental fuel requirements to add the capacity to self-generate electricity can be lower than the cost of electricity from the utility.
ENHANCE REVENUES	Opportunities exist for the company to sell excess power to neighbouring companies, residences or to the utility and, in doing so, supplement its revenue.
OFFER FUEL FLEXIBILITY	Cogeneration systems can be designed to use: biomass (i.e., domestic waste, wood, peat, agricultural products); industrial by-products (such as black liquor); natural gas; or coal.
PROTECT THE COMPANY FROM POWER INTERUPTIONS	A company can rely on its own electrical and thermal generation system.
INCREASE POWER QUALITY	Cogeneration systems that use synchronous generators can improve voltage levels, voltage stability, and power factor.
OFFER SHORT START-UP TIMES	Some systems such as gas turbines, can reduce the need for spinning reserve capacity because a gas turbine can go from a cold start to full load in 10 to 15 minutes, significantly shorter than a steam turbine that requires 6 to 8 hours.
REDUCE WASTES	Some cogeneration systems can save money required to dispose of waste material in areas with stringent environmental clean-up requirements. Wastes from some types of cogeneration systems can even be used as raw materials for other products like roads.

SOURCES: See *Supra*note 10.

Figure 4.2
Cogeneration Opportunities for Utilities

DEFER CAPACITY NEEDS	Industrial cogeneration may provide incremental power cheaper than the utility, particularly since many utilities are being constrained from building large-scale facilities by regulators in the absence of significant demand growth and in light of environmental opposition.
REDUCE LINE LOSSES	The use of industrial cogeneration when long-line extensions are required can reduce line losses.
REDUCE RISK	The idea behind reducing risk in electric power planning is to: (i) diversify across fuels and/or electrical conversion technologies to reduce energy price and project risk, (ii) develop projects that more closely match demand to reduce demand forecast risk, and (iii) have diversified project ownership.
EXPAND BUSINESS OPPORTUNITIES	The utility can expand business opportunities by providing any one or a combination of the three following services. (i) Provide technical services for the cogenerator. Because electric utilities are experts in electrical generation, they can offer their technical expertise to the cogenerator in areas such as power quality, project design assistance, pre-feasibility studies, or system maintenance. (ii) Provide sales opportunities and transmission service for excess power. The excess power generated by cogenerators can be sold to other utility customers in addition to transmitting the power to these customers. (iii) Provide transmission service to the cogenerator's customer (alone, this is more commonly referred to as *retail wheeling*).

SOURCES: See *Supra*note 10.

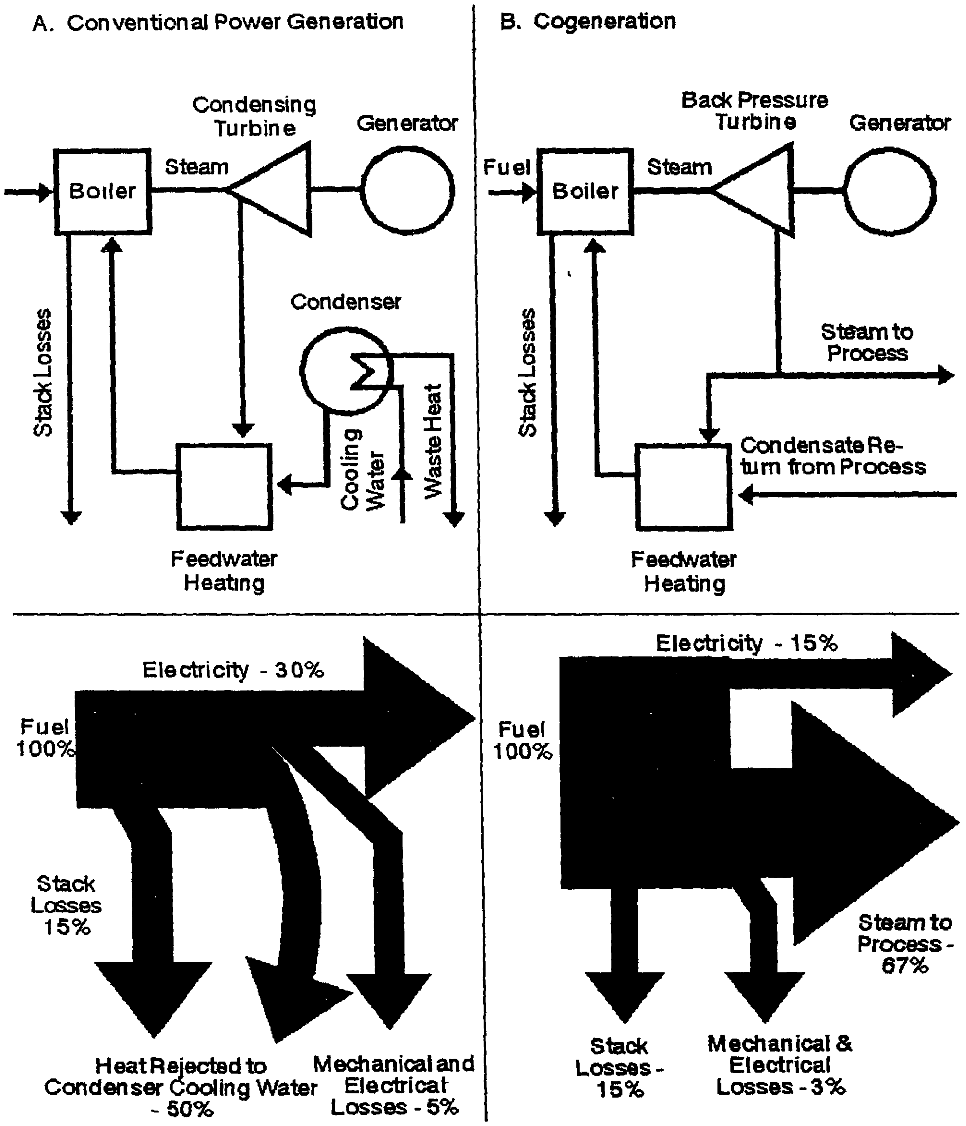
Figure 4.3
Cogeneration Opportunities for Society and Ratepayers

MORE EFFICIENT USE OF RESOURCES	The utilization of heat that was previously wasted during electricity generation is a better use of resources from society's point of view. It translates into more energy available now and/ or in the future.
REDUCE EMISSIONS	Increases in fuel use efficiencies can translate into less pollution.
LOWER ELECTRICITY RATES	The impact on rates requires further investigation; however, to the extent that the utility defers capacity and reduces risk, this should translate into lower long-term rates, all else held equal.
INCREASE EMPLOYMENT	In ranking between small thermal based generation and large-scale hydro facilities it has been found that the highest level of job creation exists with small-scale thermal facilities.
REDUCE UTILITY DEBT	Cogeneration projects are small projects that can be added to an electric system in small increments, creating the potential for the utility to incur less debt.

SOURCES: See *Supra*note 11.

Figure 4.4

Comparison of Conventional Utility Power Generation and Cogeneration



SOURCE: Cogeneration Associates Limited, *Industrial Cogeneration in Ontario*, report prepared for the Ontario Ministry of Energy (Toronto: Ontario Ministry of Energy, October 1980).

This overwhelming differential begs the question of why cogeneration is not used more extensively for both electric and thermal power generation. First, it is important to note that even with these low efficiencies, conventional electricity generation remains the optimal choice if electricity is the primary end-product; see, for instance, the low electrical output in the cogeneration case in Figure 4.4. Second, the utility is limited to selling the excess steam from cogeneration for local residential and institutional heating because steam cannot easily be transported long distances as piping costs increase dramatically with distance,[2] and the waste heat is not of high enough quality to be suitable for industrial processing. Even where steam is converted to hot water and shipped via plastic pipes for heating of nearby homes, offices, and industries, the economics is limited by the economics of heating load and pipe distance.[3]

The cost of cogeneration systems relative to electrical and heating load requirements for residences makes it impractical for this group. Thus, the real cogeneration potential is limited to institutional heating requirements and industrial processes.

In the consideration of the suitability of cogeneration for industry and institutions, the potential for conserving fuel through cogeneration depends on the user's demand for electricity and heat, and also on the type of cogeneration system used. In order to capture the optimal level of efficiency, these requirements should be (i) large and continuous, and (ii) reasonably well balanced in terms of sizing and timing of the thermal and electrical loads.

It is, however, rare that thermal and electrical loads are perfectly matched and, even where they are, the match is not continuous, as heat and electricity demands usually vary over the year. As such, arrangements are usually made to buy, sell, or store the electricity.[4] If the cogenerator is unable to reach agreement with the utilities to buy and sell power and the storage possibilities add too much to the cost, the excess power will have to be wasted.

Furthermore, the technology chosen impacts the level of efficiency Cogeneration systems based on diesel engines or combustion turbines can produce higher electricity to steam ratios. A combined cycle cogeneration system using a combustion turbine and an exhaust-heat boiler produces 30 percent of electricity with 47 percent of input heat in exhaust steam. A diesel cogeneration system using an exhaust-heat boiler produces 36 percent of electricity with each 27 percent of heat in exhaust steam. These ratios of electricity to steam are based on a steam pressure of 3 bars, which is somewhat low for average industrial use.

For the higher pressures required in many steam systems, the electricity to steam ratio will be lower in the case of steam turbine cogeneration, but higher for the combustion turbine or diesel engine modes. However, in any system designed for higher electricity/steam ratios, the fuel

consumption per unit of electricity also increases and the energy conservation potential is diminished.

Thus, the gains for cogeneration are limited to an even narrower band of candidates: institutional heating and some industries with high and relatively even thermal and electrical demands.

4.1.3 The Prime Candidates for Cogeneration in India

Given the aforementioned caveats for suitability of cogeneration to industry and the hot climate in India, the candidates for cogeneration would include industries with substantial combined heat and power requirements, such as sugar, textile, paper, fertilizer, food processing, chemicals and petrochemicals. Cogeneration is already being practiced in various industries such as pulp and paper, rayon, sugar, chemicals and fertilizers

4.2 Status of Cogeneration in India

In India, approximately 30 percent of the electricity used in the pulp and paper industry is cogenerated with the steam production in paper mills. Another area in which cogeneration has been actively deployed is in the fertilizer industry. For example, almost all the energy requirements of the ammonia and urea plants are met by steam generated through high pressure waste-heat boilers Despite the fact that cogeneration systems are in use in these industries, there are no efforts to optimize the steam and electricity requirements for various reasons Many industries continue with non-optimal systems for reasons such as company investment criteria, unavailability of equipment, concerns about the incremental costs and reliability of cogeneration equipment, and above all, government regulations. Also, no efforts are made towards installing cogeneration systems which could generate surplus electricity

4.3 Cogeneration Potential in India

The industrial sector in India has traditionally been the largest consumer of commercial energy, accounting for about 52 percent of total energy consumption. The energy intensity in the Indian industry is notably higher than that in the industrially developed countries. For example, the specific energy consumption in the cement industry is 1.755 Gcal in India compared to the world average of 1.318 Gcal. The specific energy consumption of a typical pulp and paper mill in India is 17.22 Gcal, whereas a Swedish mill of the same type consumes only 9.74 Gcal.

Under the New Economic Policy, the industrial sector has undergone a major change due to liberalization and is now faced with rapidly growing energy requirements to support its economic development. One of the

major ways of meeting this requirement is to improve its existing energy efficiency and adopt energy-efficient technology like cogeneration, which will cut production costs and reduce unnecessary consumption of energy.

There have been very few definitive studies undertaken to estimate the potential for cogeneration in India, but the results presented below are broadly indicative of this potential.

(1) The National Productivity Council (NPC) carried out a macro study on the feasibility of cogeneration for a wide cross section of Indian industries in 1979. The study estimated cogeneration potential of 421 MW in 28 of the 150 units surveyed (Table 4.1). The study further estimated that over 1500 MW of additional power could be generated with marginal investments in cogeneration systems. Reviewing the status of energy systems in these units, the study pointed out the following factors responsible for sub-optimal systems:

Table 4.1

Cogeneration Potential Estimated by the NPC Study

Industry	Number of Units Surveyed	Total Power Demand (MW)	Cogeneration Potential[a]
Paper and pulp	3	37.5	56.0
Refineries	4	37.3	40.0
Rayon	3	17.1	28.0
Chemicals	9	33.0	47.0
Fertilizers	9	193.0	250.0

[a]The cogeneration potential has been determined on a site by site basis.

SOURCE: National Productivity Council, New Delhi, 1991.

- general tendency for most units is to generate steam at the maximum process pressure;
- the demand for low pressure steam is met by and large through pressure reductions,
- rationalization in choice of process steam pressures has not been resorted to, and
- power is purchased from the grid for driving prime process movers, refrigeration etc..

(2) In 1983, an Inter-ministerial Working Group on Energy Conservation estimated that the economic potential for cogeneration in India's major industries was about 1500 MW.

(3) TERI recently carried out a detailed survey of 300 industrial units in the country from which it estimated cogeneration potential (Table 4.2). These cogeneration estimates are

based on the internal heat to power ratios which would meet the plant's energy requirements and based on the existing production capacities of the various industry categories. Of the total estimated cogeneration potential of 7574 MWs, the sugar industry accounts for over 65 percent of the total cogeneration potential. The potential is also significant (500-600 MW) in the textile and paper industries. If one considered the adoption of systems designed to maximize power production, rather than to meet within plant energy requirements, the cogeneration-based power potential would be much greater.

Table 4.2

Cogeneration Potential Estimated by TERI
(1993)

Industry	Potential (MW)	Percent
Alumina	59	0.8
Caustic soda	394	5.2
Cement	78	1.0
Cotton textile	506	6.7
Iron & steel	362	4.8
Man-made fibre	144	1.9
Paper	594	7.8
Refineries	232	3.1
Sugar	5131	67.7
Sulfuric acid	74	1.0
Total	7574	100.0

SOURCE: Tata Energy Research Institute, 1993.

The potential market for cogeneration in Indian industry will be influenced by energy prices, the economic situation, restructuring tariff regimes and/or the introduction of financial aids. National energy policies could also make the electricity supply industry open for competition.

4.4 Constraints to Cogeneration in India

While the extent of energy conservation potential through the application of cogeneration systems is well appreciated, there are several barriers which impede the adoption of cogeneration by Indian industry. The following general list of barriers is based on a literature review together with discussions with end users, equipment manufacturers, and government officials in India.

Regulatory uncertainty - The key regulations that qualify and regulate cogenerators are relatively new and are still being considered by the utility industry. The SEBs have no regulations concerning cogeneration; only three of the SEBs have taken steps in this direction mainly for bagasse-based

cogeneration. Changes in government policy concerning other investment incentives, tariff, banking and wheeling facilities, can also greatly affect the market.

Stricter air quality standards - Pollution regulations recently introduced by the Ministry of Environment and Forest (MOEF) could substantially add to the initial capital investment required for a cogeneration unit. The increased capital cost and, in some cases, reduced system performance, will discourage the use of certain cogeneration technologies.

Changing utility buy-back rates - Electric utility buy-back rates are negotiated for each cogeneration site and are determined by the utility's avoided costs. As the structure of the utility industry changes and as more cogeneration capacity is brought on line, these buy-back rates may decrease and discourage further cogeneration.

A reluctance to enter the power business - Most manufacturing concerns have become accustomed to simply purchasing power and generating steam or process heat on-site. The prospect of adding a cogeneration system represents a large capital investment in what is usually an unfamiliar technology.

Electric utility resistance - Many electric utilities have adequate or excessive capacity at off-peak periods and therefore have little incentive to purchase electrical power from a cogenerator Other utilities disagree with the distributed on-site power concept, having grown accustomed to large, central station domination of the electric utility sector

Lack of cogeneration expertise - Most industrial concerns do not have in-house personnel capable of evaluating and operating cogeneration systems. In general, cogeneration technology expertise has been confined to specific industries that have traditionally used equipment of this type.

Perceived unreliability of gas turbines - Gas turbines, which are typically perceived as high speed and sensitive equipment, are not generally used in many industrial prime mover applications Most gas turbines are used in power producing applications as peaking generator sets, and require frequent maintenance due to the severe start-up and shut-down operating cycle

Limited capital resources - Many industrial concerns do not have sufficient internally generated funds, or are unwilling or unable to obtain external funds for cogeneration systems.

Higher priority of production oriented projects - Cogeneration projects, oriented to energy savings, take a lower priority than production oriented projects. Higher returns on investment are typically required with energy saving projects when competing for limited capital budgets with production projects.

Sensitivity to energy prices - Small variations in the input and output utility costs of a cogeneration unit could easily destroy the economics of the project.

Possible plant closings - Companies will limit the scope of capital investment targeted at plants that may be severely curtailed or closed as a result of changing business or economic climates. Cogeneration projects typically require years of steady operation to be economically viable, and therefore, tend to be of limited interest to many industries.

Premium fuel availability - Only recently have natural gas and oil been available in adequate supply and at reasonable prices to the industrial sector throughout the entire year The long-term availability of reasonably priced premium fuel is crucial to the successful implementation of several cogeneration technologies

Limited floor area - Most cogeneration systems are retrofitted into existing manufacturing facilities with limited available floor space Adequate plant space for the proper operation and maintenance of the cogeneration unit in an area that is accessible to plant utility tie-ins are important considerations.

High capital cost for cogeneration systems - The available prime mover technologies limit the potential sizes of cogeneration systems to relatively large and expensive units. The high initial capital cost of cogeneration systems is a barrier in industries with limited financial strength.

Proper size and thermal to electric output match - Accommodating the application's energy stream requirements with that available from the various technologies is instrumental to a successful project. Most cogeneration technologies have relatively fixed thermal to electric outputs and most applications have daily and/or seasonal variations in utility requirements. There appears to be a unique need in India for small, packaged gas turbine cogeneration systems

Adequate water supply - Many cogeneration technologies use heat recovery boilers that require a steady supply of high quality feedwater.

New production technologies that reduce energy use - New manufacturing technologies are emerging that could drastically reduce the electric utility requirements of current industrial processes. This potential change in energy usage or change in the composition of energy required could alter the viability of certain cogeneration technologies.

Research and development - There is a need to identify areas of research and development in the various cogeneration technologies required in India.

Understanding the barriers that a new technology faces in the market is the first step in developing an effective project strategy. The identified market barriers encompass a wide range of business, government policy, institutional, regulatory, financial, environmental, economic, and technology problems. As such, some of the major barriers are discussed in further detail below.

4.4.1 Technology

Cogeneration systems designed to maximize electric power production require high pressure and high temperature system parameters. High pressure boilers, turbines and accessories are not available in sufficient quantities within India at this time. Turbines at high pressure are presently imported. There is also a considerable technological gap between what is available in India and the various advanced configurations and systems available in the developed countries. Table 4.3 indicates the various technologies available.

4.4.2 Financial Constraints

One of the major problems for a firm interested in cogeneration is the relative capital cost of a cogeneration system. Costs may range from $500 to $1000 per kilowatt of installed capacity for oil and gas systems and $1000 to $1500 for coal, wood, or biomass systems. In times of high interest rates and credit restrictions, such as those recently experienced in India, this capital intensity makes the financing of cogeneration systems a major impediment to their successful development. Hence, industries find it difficult to raise financial resources for the incremental cost of setting up a cogeneration system with the objective to sell surplus power to the utilities. Moreover, the tax and duty structure on the capital equipment used for a cogeneration facility is not as attractive as is the case for other non-conventional energy sources.

Where the firm's overall economic picture limits its ability to use the tax benefits associated with such projects, third-party ownership appears to be required to address this problem in India. Liberal credit facilities such as concessional interest rates, larger repayment period, etc. should also be provided to encourage greater industrial cogeneration.

4.4.3 Legislative Constraints

Presently, there is no legal framework for the purchase of surplus cogenerated power. Unlike the situation in the United States, where Public Utilities Regulatory Policies (PURPA) makes it mandatory for public utilities to buy the energy generated by cogenerators at avoided cost, there is no such requirement in India. Very few (SEBs) have encouraged cogeneration. In fact, the self-generated sales tax imposed by the state tax authorities acts as a disincentive for industries who might otherwise be interested in assessing cogeneration. Except for a couple of SEBs, electric utilities do not have any

Table 4.3

Status of Cogeneration Technologies Available Abroad

S. No.	No. of design options	State of the art	Technology	Fuel type
1	10	Current	Steam Turbine	Petroleum Boiler Fuel
2	10	Current	Steam Turbine	Coal
3	2	Current	Diesel, High Speed	Petroleum distillate
4	1	Current	Diesel, Low Speed	Petroleum boiler fuel
5	4	Current	Gas turbine	Petroleum combined distillate
6	1	Current	Steam Turbine	Petroleum distillate
7	10	Advanced	Steam Turbine	Coal derived boiler fuel
8	10	Advanced	Diesel, High Speed	Coal (AFB)
9	1	Advanced	Diesel, Low Speed	Coal derived
10	2	Advanced	Diesel, low speed	Coal derived distillate
11	1	Advanced	Gas turbine	Coal derived boiler fuel
12	5	Advanced	Gas turbine	Coal (pulverised)
13	5	Advanced	Gas turbine	Petroleum boiler fuel
14	2	Advanced	Gas turbine	Coal derived boiler fuel
15	4	Advanced	Gas turbine, indirect	Coal (gasifier)
16	3	Advanced	Gas turbine, closed cycle	Coal (PFB)
17	5	Advanced	Gas turbine, closed cycle	Coal (AFB)
18	5	Advanced	Steam injected gas turbine	Coal derived boiler fuel
19	2	Advanced	Steam injected gas turbine	Petroleum boiler fuel
20	2	Advanced	Steam injected gas turbine	Coal derived boiler fuel
21	2	Advanced	Steam injected gas turbine indirect	Coal (PFB)
22	2	Advanced	Combined cycle	Coal (AFP)
23	3	Advanced	Combined cycle	Petroleum derived

Continued On Next Page

Table 4.3 (Continued)

S. No.	No. of design options	State of the art	Technology	Fuel type
24	3	Advanced	Combined cycle	Coal derived
25	1	Advanced	Combined cycle	Coal (PFB)
26	2	Advanced	Combined, indirect	Coal (AFP)
27	2	Advanced	Fuel cell, low temp.	Petroleum distillate
28	2	Advanced	Fuel cell, low temp. distillate	Coal, derived
29	2	Advanced	Fuel cell, high temp.	Petroleum distillate
30	4	Advanced	Fuel cell, high temp.	Coal, derived distillate
31	1	Advanced	Fuel cell, high temp.	Coal, gasifier
32	2	Advanced	Sterling	Coal, derived distillate
33	2	Advanced	Sterling	Coal, gasifier
34	2	Advanced	Thermionics	Coal derived boiler fuel
35	3	Advanced	Thermionics compound	Coal derived boiler fuel cycle
36	10	Current	Steam turbine	By-product heat bottoming
37	3	Advanced	Organic	By-product heat rankine bottoming

SOURCE: Tata Energy Research Institute.

arangements for the wheeling and banking of cogenerated power. It is important to have long-term purchase contracts between the SEBs and cogenerators for purchase of surplus power to encourage industries to opt for cogeneration under power maximization mode.

4.4.4 Pricing Policy and Cost Considerations

A crucial factor in promoting cogeneration relates to agreement on the tariff policy. Except for a couple of SEBs, electric utilities in India do not have any formal policy for purchase of cogenerated power.

Ideally, utilities should pay cogenerators the avoided cost of their own power generation or what it would cost to purchase equivalent power from another source. Utilities however, under the principles of grid discipline, consider only short run marginal costs (fuel and operating costs) in their decision-making. This makes cogeneration uneconomic and, therefore, deters investments by industry. Under the power maximization option, where incremental capacity is added by the industry with the sole objective of supplying to the grid, the cogenerator must be paid both capacity as well as the variable costs. This also requires that utilities, while carrying out their long term planning exercise, must consider cogeneration option as a source of firm power supply in relation to conventional power generation options

4.4.5 Technical Barriers and Problems of Parallel Operations

The quality of electric power supplied by India's electric utilities has always been a major problem--high voltage fluctuations, frequency variations, and frequent power failures. These factors should be considered in assessing the cost of a cogeneration plant. The cogenerator may have a slightly different set of concerns, such as safety, interconnection costs, production of the cogeneration system, power factor cost, and impact on production.

Utility system reliability is also affected by the location of the cogeneration interconnection on the utility system. If the interconnection is at a transmission level, then interruptions of service have greater impact than those at the distribution level. The utility may require even more stringent protection requirements of cogenerators connected to the transmission system to protect other customers downstream of the cogenerator.

Another consideration is the generator size compared to the plant load and the load on the utility life. This will usually result in more stringent protective requirements since the utility and cogenerator will again seek to protect utility and customer equipment from service disruptions.

Both the cogenerator and the utility need to protect their respective personnel and facilities from injury and damage that could be caused by generator malfunction. This protection often utilizes automatic equipment to detect and isolate the faulty sections of a circuit, so that the remainder of the network can continue to deliver power without interruption.

When cogenerators are present, several areas of utility planning may be affected because of the dispersed locations of the cogenerators. These impacts may show up in the following areas--voltage regulation, load restoration after interruptions, and insufficient circuit capacity.

Utilities will need to account for deviations from their expected load surveys and load factors caused by dispersed generation. These form the foundation of utility planning. Both of these are affected by dispersed generation, which is usually not planned for and displaces some electrical demand as well.

4.5 Measures Undertaken to Encourage Cogeneration in India

In recognition of the gains from cogeneration, the Government of India has endeavoured to facilitate more development in India. On the issue of tariffs for electricity purchases by electric utilities, recent initiatives taken by the Government of India in the power sector and particularly in the sugar manufacturing sector indicates that the State Electricity Boards (SEBs) are likely to change their tariff structure for cogenerated power.

In particular, the Ministry of Power, under their policy to encourage private sector participation in power generation, have introduced a two-part tariff system which would guarantee returns to the private investors. The first part of the tariff ensures recovery of fixed costs (including returns) based on performance at normative parameters. The second part ensures meeting of variable expenses, based on units of electricity actually supplied. Incentives will be provided for the achievement of efficiency levels, higher than the normative parameters. Once the rate for sale of power is fixed, no limits of any sort will be put on actual profits earned by a generating company. The system also provides for the signing of a Contractual Agreement, laying down rates for the bulk sale of power by a generating company to an SEB for a specified period.

These developments will set a precedent for other industries to exploit these changes and generate surplus power to their maximum potential and export to the grid and/or sell to a third party. The major investment in cogeneration is likely to be realized only by independent producers supported by regional electricity distribution companies and the SEBs.

Although these measures address the issue of buy-back rates for electric power purchases from cogenerators by electric utilities, they do not

address many of the other barriers to cogeneration, such as capital cost, utility reluctance to purchase power, etc. Many of these issues imposed similar impediments to cogeneration in North America. However, various government policies and utility programs have served to alleviate them. Thus, it is instructive to investigate how programs and policies have advanced cogeneration in North America.

4.6 Cogeneration in North America

4.6.1 Status of Cogeneration in North America

There has been a flurry of industrial cogeneration activity in the last 15 years in North America. In the U.S., expectations are that industrial cogeneration will increase from 28,613 MW in 1991 to 63,554 MW in 2010.[5] In Canada, expectations are that industrial cogeneration will climb to 4221 MW by 2010 from a current level of just under 1000 MW.[6]

The extraordinary growth in popularity of industrial cogeneration and, in particular, gas-fired cogeneration can be attributed to several factors. First, the technology itself has advanced in terms of efficiency, reliability, and sophistication. Second, utilities are facing increasing costs as the technical economies of large-scale generation facilities[7] have been reached and more stringent environmental controls place increasing cost pressure on conventional central plant generating technologies. Third, growing interest in protecting the environment and demands for greater energy efficiency have turned attention to cogeneration. Fourth, low natural gas prices have enhanced the commercial prospects of industrial cogeneration. And finally, governments are actively promoting cogeneration through various means, including requirements for provincially-owned electric utilities to purchase cogenerated power and tax breaks for cogenerators.

4.6.2 Strategies for Promoting Industrial Cogeneration

Governments in Canada and the U.S. have taken markedly different paths to promoting industrial cogeneration. The U.S. has elected to design very specific legislation supporting cogeneration whereas Canada relies on a market approach with tax incentives for specified cogeneration activities.

4.6.2.1 Selected Provincial Policies and Utility Response

Until quite recently, the mainstay of the 'Canadian' approach has been for governments to direct their publicly-owned electric utilities to increase the system share of non-utility generation in general and cogeneration specifically, often by setting target guidelines.[8] Because electric utilities are publicly-owned, compliance has not been an issue in Canada.

Government intervention encouraging cogeneration has been most prominent in those jurisdictions offering the greatest cogeneration potential, those being Ontario--74 percent of projected cogeneration potential; Québec--11 percent; and British Columbia--11 percent.

(i) Ontario - In 1989, the Ontario Ministry of Energy requested that Ontario Hydro solicit proposals for 2000 MW of non-utility generation projects by the year 2000.[9]

(ii) Québec - In its 1988 Energy Policy Plan, the Québec Government made a statement of intent for Hydro Québec to devote attention to independent power production--in particular, small hydro projects and development of technologies which use renewable energy, hydrogen, and urban waste.[10]

(iii) British Columbia - The British Columbia Government recently announced that it will give independent power producers an equal opportunity to meet demand.[11] The new project evaluation technique is to be based on social costing to recognize 'financial, environmental, and economic development features'. The government also wants a movement away from wood residue and small hydro generation.

4.6.2.2 Canadian Tax Incentives

Investment in cogeneration directly by industry is also encouraged through a special federal tax provision called Class 34, Accelerated Capital Cost Allowance. This tax incentive applies to assets that save energy or use renewable sources of energy.

Basically, the mechanism allows the company to write-off eligible assets over 3 years--up to 25 percent in the first year, up to 50 percent the second year, and the balance in the third year. In contrast, capital equipment without cogeneration potential receives either a 6 percent or 20 percent declining balance write-off.[12]

4.6.2.3 The U S. Public Utilities Regulatory Policies Act (PURPA)

The primary intent of PURPA has been to encourage cogeneration and small power production using non-conventional fuel sources. In recognition of the electric utilities' control over virtually all aspects of electric power, this legislation broadened the Federal Energy Regulatory Commission's (FERC's) role to include the establishment of rules guiding electricity pricing, electric power sales, and wheeling by these parties in conjunction with the electric utility, thereby forcing electric utilities to use these 'underutilized resources.'

FERC's guidelines specifically direct electric utilities to purchase all electricity from *qualifying* non-utility generators at rates bounded by what is deemed 'reasonable and just' and not exceeding the utility's *avoided costs*. A 'qualifying facility' includes:

(i) those generation facilities with capacity less that 80 MW for which at least 75 percent of the energy inputs must come from biomass, waste burning, renewable resources, or geothermal heat; and

(ii) cogeneration facilities.[13]

'Avoided costs' encompass all costs incurred by the utility in providing the same electricity service that would be avoided. The Act provides an exemption to the cogenerator from regulation as a public utility, from state regulation of rates and other financial and economic matters such as equity among customers, and from detailed accounting requirements.

Much of the cogeneration activity in the U.S. has been attributed to PURPA.[14] The U.S. Energy Information Administration estimates that one-fifth of all capacity additions in the U.S. during the 1980s were installed by non-utility generators (NUGs) and expects that one-half of all capacity additions in the 1990s will come from NUGs.[15]

Notwithstanding the fact that the overall quantity of cogeneration has increased significantly, PURPA itself has been questioned in a number of studies.[16] Of the criticisms levelled, most center on FERC's preference for avoided cost without a consistent methodology for its application. FERC's refusal to endorse an avoided cost methodology, leaving such decisions to individual states, has translated into broad interpretation of avoided costs across the United States. In some cases, rates given to qualified facilities are supplemented; in other cases, rates are undervalued relative to the true avoided costs. For instance:[17]

- some states have chosen a rate that applies to all utilities regardless of the actual avoided costs of the individual purchasing utility;

- some states use certain units of electric power to set the rates for qualifying facilities, e.g. oil and gas-fired plants, rather than the incremental system costs of power;[18]

- some states offer 'incentives' to qualifying facilities which are not linked to the utility's avoided cost, but are subsidies to further stimulate development of qualifying facilities; and

- there are also restrictions on the ability of the utilities to procure capacity *via* competitive bidding from qualifying facilities on a least cost basis.

These strategies mean that rates paid to qualifying facilities sometimes bear little resemblance to avoided costs meaning higher customer rates and/or lower shareholder returns.

Another PURPA failing is that purchases of power from qualifying facilities are required regardless of reliability and availability of the facilities or whether the utility even needs the additional capacity. Because utilities are required to provide reliable power on demand, this means utilities have to either purchase additional power or build additional capacity to fill in any gaps caused by the failure of qualifying facilities to meet their obligations to the utility.

While the quantity of cogeneration (and independent power) has increased, PURPA has failed to deal with the efficient provision of non-utility generation. Moreover, there is little evidence to suggest that utility purchases from qualified facilities, as required by PURPA, translate into reduced rates, reduced reliance on scarce fuels, and increased efficiency of electric power--the stated intent of PURPA.

4.6.2.4 The U.S. Energy Policy Act of 1992 (EPACT)

Widely heralded as the most significant piece of energy legislation since the 1970s,[19] the Energy Policy Act of 1992 provides the framework for the ultimate transition to competitive generation. This Act creates a new classification of power producers--called the 'exempt wholesale generators' (EWGs).[20]

EPACT stands above PURPA in several important ways. First, producers will have to compete in order to build capacity. Second, they will not have to meet PURPA's guidelines or fuel use requirements. Third, utilities are not required to purchase power from the EWGs.

This Act gives FERC the power to order utilities to provide access to transmission on their transmission lines. However, FERC cannot order the transmission of power to a final consumer, known as 'retail wheeling'. Moreover, FERC is to ensure that to the extent possible, the costs are recovered from the transmission customers and not from the utility's existing customer base.

PURPA and EPACT both are in effect in the U.S. today. While EPACT broadens the scope of PURPA and removes many of its uneconomic guidelines and restrictions, PURPA will continue to protect and promote those facilities which generate electricity using the chosen fuels under the Fuel Use Act.

4.6.2.5 Utility Strategies

Increasingly, issues of concern to electric utilities in North America are being handled in a broadly defined paradigm called *integrated resource planning* (IRP). Essentially, IRP changes the focus of utility planning from utilities as kW suppliers to *energy service* providers changing the traditional utility mandate to encompass the 'design of demand-side management (DSM) programs which promote the efficient use of electricity'. Utilities must now weigh the benefits and costs of DSM programs in relation to generation, distribution, and transmission facilities in meeting demand.

The element of importance in the context of cogeneration (and dispersed electricity generation) is that utilities must now also consider non-utility generation projects as supply-side alternatives and evaluate alternative strategies to their traditional utility-owned and-operated generation facilities. In addition, utilities must reconcile the environmental implications, and the benefits and costs of all options--demand-side and supply-side--in meeting system load. Integrated resource planning is being used in British Columbia, Alberta, Ontario, and Québec to varying degrees to help utilities counter increasing pressures from competing energy forms, government, regulatory authorities, and the public.

A natural outgrowth of IRP is interest in *all supply-source/competitive bidding*. The main issue in relation to resource acquisition centers around the contractual arrangements with independent power producers.

The key factors in competitive bidding are listed below.[21]

(i) Price - Typically, the bid price is benchmarked against the utility's avoided cost--which becomes the price ceiling. Companies which offer lower prices are ranked higher. Utilities may or may not disclose their avoided costs.

(ii) Payment Schedule - If a company wants a significant portion of its contract up-front, the utility may penalize the contractor. This is because if the utility has relatively low, short-term avoided costs, the utility may in effect pay more than its short-term avoided costs to the independent power producer. The utility has opened itself up to substantial risk if the project fails.

(iii) Supplier Assurance - This term is used to reflect various project viability factors such as likelihood of successful project development and completion, and long-term project viability.

(iv) System Optimization - This measure reflects the 'operational fit' between project and utility operating characteristics. The single most important factor in this category is dispatchability.

(v) Environmental Factors - This term is usually measured by fuel use and projects are ranked by level of environmental emissions. Low polluting, solar or wind, electro-conversion systems get higher scores than oil and gas systems.

(vi) Fuel Choice and Flexibility - This factor relates to the utilities concerns about fuel diversity which in turn lowers their risk.

(vii) Contract Length - The range of contracts is between 5 and 25 years. Most utilities place constraints on the contract length at the onset of the bidding.

(viii) Maximum Bid Size - A utility may place a size constraint or weight various projects in terms of sizes.

Hydro Québec uses long-term avoided cost as a benchmark to rank alternatives combined with fuel use objectives. For instance, small hydro projects and technologies that use renewable energy, hydrogen, and urban waste are favoured over projects which use fuels such as oil and natural gas. All contracts are for a set length of time of 20 years,[22] and project risk is borne by the independent power producer.[23]

Ontario Hydro broadly divides projects into two categories: those greater or less than 5 MW. Rates for projects greater than 5 MW are negotiated on a contract-by-contract basis whereas avoided costs form the basis for power purchase rates from projects of less than 5 MW.

In B.C., the government has directed B.C. Hydro to develop a strategy aimed at ranking the various alternatives in line with B.C.'s multiple objectives of efficiency, environmental quality, economic development, and tax consequences of each project.

4.7 Conclusions

Clearly, potential exists for cogeneration in energy intensive industries such as sugar, textiles, paper, fertilizer, food processing, chemicals and petrochemicals in India. However, various impediments are deterring its broader application. Modifications to tariff policy in India has been a useful first step towards reducing one of the barriers, but other obstacles remain. The experience gained in North America in removing many of the same barriers illustrative of measures that would prove useful to consider in India, and those that may not. For instance, analysis indicates that PURPA encouraged cogeneration, but it did not do so efficiently. In its place, IRP has emerged as a key tenet in efficient resource allocation for the electric power sector. IRP appears to be a resolution to our successes as well as our failures in implementing cogeneration, DSM and environmental externalities and holds considerable promise for application in Indian electric power sector development.

Endnotes

[1]Useful as distinct from waste heat dissipated during electricity production.

[2]Anthony E. Reinsch and Ellen F. Battle, *Industrial Cogeneration In Canada: Prospects and Perspectives*, CERI Study No. 24, (Calgary, Alberta: Canadian Energy Research Institute, March 1987).

[3]Morgan MacRae, *Community Integrated Energy Systems*, CERI Study No. 45 (Calgary, Alberta: Canadian Energy Research Institute, June 1992).

[4]If none of these options exist, the company would have to dump the thermal energy rather than use it to generate electricity. Dumping could only be a short term prospect because it would eradicate the justification for having the cogeneration system in the first place.

[5]Gas Research Institute, *1993 Edition of the GRI Baseline Projection of U.S. Energy Supply and Demand to 2010* (Chicago, Illinois: GRI, June 1993).

[6]Energy, Mines, and Resources Canada, *Electric Power in Canada* (Ottawa, Ontario: EMR, 1992).

[7]Robert H. Williams and Eric D. Larson, "Expanding Roles for Gas Turbines in Power Generation," ref.

[8]See for example: Ontario Ministry of Energy, *Parallel Generation Policy Paper*, (Toronto, Ontario: OMEE, 1989).

[9]Ontario Ministry of Energy and Environment, *Parallel Generation Policy Paper* (Toronto, Ontario: OMEE, 1989).

[10]Discussions with Claude Desjarlais at the Québec Ministry of Energy.

[11]Ministry of Energy, Mines, and Petroleum Resources, Province of British Columbia, *News Release*, October 15, 1992 and supporting background information.

[12]The accelerated status can also be given to projects that utilize renewable resources.

[13]Cogeneration facilities must also meet criteria relating to system configuration, heat utilization, and minimum efficiency standards.

[14]Northwest Power Planning Council, *Northwest Conservation and Electric Power Plan*, Volume II, Chapter 8 (Portland, Oregon: NPPC, 1991).

[15]Energy Information Agency, *The Changing Structure of the Electric Power Industry 1970-1991* (Washington, D.C.: EIA, March 1993).

[16]Lindsay Pfeffer and Associates, Inc., *Emerging policy Issues in PURPA Implementation*, prepared for the U.S. Department of Energy, (Washington, D.C.: DOE, March 1986).

[17]Unless otherwise stated, these points have been discussed in Lindsay Pfeffer and Associates, Inc., *Emerging policy Issues in PURPA Implementation*, prepared for the U.S. Department of Energy, (Washington, D.C.: DOE, March 1986).

[18]Energy Information Agency, *The Changing Structure of the Electric Power Industry 1970-1991* (Washington, D.C.: EIA, March 1993).

[19]EIA (1993), p. 27.

[20]This legislation was designed to break the powerful trusts which, at that time, essentially controlled the electric distribution network. PUHCA provided the Securities and Exchange Commission with the authority to break up these trusts, to limit utilities to the jurisdiction of single states, to confine activities to the business of operating a utility and the associated activities, and to regulate the reorganized industry to cap their return.

[21]Charles A. Goldman and Edward P. Kahn, "Competitive Bidding for Electric Power: Comparing Evaluation Methods," *Energy Systems and Policy*, Vol 13 (1989) pp 169-191.

[22]This corresponds to the expected in-service date for their major hydro project, the Grande Baliene

[23]Tony Frayne, Hydro Québec.

Chapter 5

TRANSMISSION AND DISTRIBUTION/ ELECTRICITY TRADE

Part A

5.1 Transmission and Distribution in India

5.1.1 Transmission and Distribution Losses

There is worldwide concern at the rapidly diminishing sources of energy, which has led to the realization of the need to develop the renewable sources of energy as well as the necessity to minimize wasteful uses of energy. In this context, the excessive transmission and distribution (T & D) losses in the power systems is a matter of grave concern. The present T & D loss figure for India is 23 percent which is not only high in comparison to corresponding figures ranging from 6 percent to 11 percent in developed countries but also in comparison to many developing countries e.g. China (10 percent), Thailand (11 percent), Taiwan (7 percent). What is more disturbing is the fact that due to various reasons the losses which stood at the level of about 15 percent until 1966/67 gradually increased to 21.74 percent in 1986-87 and has since shot up to about 23 percent, not showing any substantial trend towards decline. However, it should be noted that the loss figure of 23 percent for India includes a fairly high component of non-technical commercial losses of 6 percent to 7 percent. Even allowing for 6 percent towards commercial losses, the technical loss figure of 17 percent for India is very high, and it should be possible to bring it down to the level of about 12 percent by making necessary improvements to the system e.g. providing necessary reactive compensations and taking measures for providing reinforcements mainly to the distribution system.

5.1.2 Present Status of Distribution System in India

The total installed generating capacity in the country in 1991-92 was about 78,500 MW and the total number of consumers was over 75 million. Apart from an extensive transmission system network at 400 kV, 220 kV, 132 kV and 66 kV which has developed to transmit the power from the generating stations to the grid substations, a vast network of subtransmission and distribution system has also come up for the utilization of the power by the ultimate consumers. An idea of the size of the distribution system can be had from Tables 5.1 and 5.2.

Table 5.1

Length of Distribution Lines in State Electricity Boards
(as on 31.3.92)

	ckt km
33 kV	153 547
11 kV	1 329 161
400 kV	2 634 595

SOURCE: Central Electricity Authority.

Table 5.2

Number of Distribution Transformers and Their Aggregate Capacity
(as on 31.3.92)

Region	Numbers	Aggregate Capacity (kVA)
Northern Region	493 997	30 434 945
Western Region	340 956	2 467 339
Southern Region	290 367	24 733 323
Eastern Region	85 634	5 865 041
North Eastern Region	13 546	1 174 290
Total	1 224 500	86 880 938

SOURCE: Central Electricity Authority.

However, due to lack of adequate investments on T & D works, the T & D losses have been consistently on the higher side, and are presently in the range of 22-23 percent. Reduction of these losses by undertaking distribution system improvement works has not been possible for want of adequate funds.

5.1.3 Transmission and Distribution Losses: Present Status and Potential for Reduction

The approximate break-up of T & D losses in the Indian power system are as follows.

Transmission Losses (400 kV, 220 kV, 132 kV and 66 kV)	4.0 percent
Distribution Losses (33 kV, 11kV and 400 volts)	19.0 percent
	23.0 percent

Out of the above losses of 19 percent at distribution level, non-technical commercial losses account for about 5 percent, and thus the technical losses in distribution system may be taken as about 14 percent. These high losses of 14 percent are primarily due to inadequate investments for system improvement works, which has resulted in unplanned extensions of the distribution lines, overloading of the system elements like transformers and conductors, and lack of adequate reactive power support. By undertaking suitable system improvement schemes based on computer studies it should be possible to bring down the technical losses in the distribution system to the level of nine percent i.e. a reduction of five percent.

5.1.4 Factors Responsible for Excessive Transmission and Distribution Losses

The main factors responsible for the high T & D losses in the Indian power systems are broadly classified in the following three categories in order of relative importance.

(i) Financial
(ii) Administrative
(iii) Technical

Details of the above three factors causing unduly high T & D losses in Indian power system is elaborated below.

5.1.4.1 Financial

There has been a general lack of appreciation amongst the planners about the importance of providing adequate T & D facilities to match with the additional generation capacity being inducted in the power system. The fund allocations for the transmission and distribution systems during the various Five-year plans have not been made on a rational basis on the vague assumption that some sort of patchwork in the existing transmission and distribution network would some how meet the requirements. According to the report of the Rajadhyaksha Committee on Power appointed by Government of India in 1978, for the development of a well balanced power system it is considered desirable to have investments in the generation and T & D sectors in the ratio of 1:1. From a study of the pattern of investment on these two sectors (see Table 5.3), it is seen that barring First plan (1951-56) when provision for generation, T & D was in the ratio of 1:1.26, the ratio of

investments in T & D has consistently declined to the level of 0.4-0.5 percent of the investment in generation over the years. Incidentally, it may be mentioned that the comparatively higher ratio of investment on transmission and distribution (1:1.26) in the First plan was instrumental in holding the transmission and distribution loss to the level of 15 percent up to 1966/67, and as a consequence of starving the transmission and distribution sector of funds in the subsequent plans the losses have shot up to the 22-23 percent level.

Table 5.3

Plan Wise Details of Investment in Power Sector

S.No.	Plan Period	Total Investment in Power Sector	Expenditure Incurred (Rs. in Crores)			Ratio Between Generation and T&D
			Generation	T&D	Others	
1	1st Plan (1951-56)	260	105	132	23	1:1.26
2	2nd Plan (1956-61)	460	250	115	95	1:0.46
3	3rd Plan (1961-66)	1 252	777	301	174	1:0.39
4	Three Annuals (1966-69)	1 223	676	291	256	1:0.43
5	4th Plan (1969-74)	2 931	1 505	768	658	1:0.51

SOURCE: Central Electricity Authority.

The fund allocations for T & D made especially during Fifth plan onwards has not been commensurate with the generating capacity additions in the system and have been found to be just adequate for holding the T & D losses at the prevailing level of around 23 percent. If the present trend of inadequate investments on T & D works were to continue in the coming plans, it would be reasonable to assume that these plan allocations would be just adequate to cater to the T & D requirements corresponding to generating capacity additions during the relevant plan periods and would be able to just limit the T & D losses to the current level of 23 percent. For implementing any program for reduction of losses to lower levels, say to 18 percent by the end of Tenth plan period (2006-07) as recommended by CEA in their Report on Perspective of National Power Development, additional funds would have to be made available to the utilities to enable them to undertake necessary system improvement works.

5.1.4.2 Administrative

(a) Although the Indian Electricity Act has recently been amended to make theft of electricity a cognizable offence, it has been reported by the utilities that due to certain legal loopholes in regard to corresponding provision in the Indian Penal Code, the percentage of successful prosecutions has been very low. They have pointed out the necessity for taking remedial measures for plugging these legal loopholes.

(b) In a majority of cases involving theft of electricity, connivance of the staff of the utilities cannot be ruled out. The utilities should therefore formulate suitable transfer

policies to counter the possibility of distribution staff developing vested interests.

(c) Deterrent punishment for errant staff and incentive schemes for honest and meritorious staff.

(d) Fixing up of responsibility at level of senior engineers for accounting of energy received and energy billed feeder wise.

(e) Review the policy of 'flat-rate power supply', which encourages wastage of electricity. Possibly even if power is supplied on flat-rate basis, electricity meters could be provided for energy accounting purposes.

5.1.4.3 Technical

(a) Development of weak and inadequate subtransmission and distribution system basically due to lack of adequate investments on system-improvement works.

(b) Implementation of large-scale rural electrification programme in the country involving extension of supply to low power factor loads (e.g., irrigation tubewell motors) over very long lines without providing necessary reinforcements to the back-up subtransmission system has resulted in unplanned and haphazard growth of the distribution system.

(c) Higher transformation losses due to the existence of many stages of transformation *via*, 132/66 kV, 66/33 kV, 33 kV/11 kV, and finally 11 kV/0.4 kV.

(d) Adoption of an inappropriate distribution technology *via*, low voltage distribution system which is suitable for countries with high load densities (like European countries) and not for a large country like India with loads thinly spread over wide areas. For India, high voltage distribution system is more appropriate which is the system adopted by USA and Canada with load density conditions similar to ours.

(e) Inadequate reactive compensation in the system.

(f) Unmetered supply to rural and agricultural loads encouraging wasteful use of electricity.

(g) Poor quality electricity meters and lack of adequate calibration facilities.

(h) Pilferage of electricity.

The growth of the distribution system in the country has been by and large, unplanned and haphazard and not based on systematic planning studies. This has resulted in very high system losses and poor quality power supply to the consumers. In the recent years only some of the state electricity boards (SEBs) have taken up systematic studies for planning of their distribution systems using the available computer software, and other SEBs are expected to follow the same strategy for their distribution planning. The

distribution system improvement measures generally adopted mainly comprise rerouting and reconductoring of lines, augmenting transformer capacitors, creation of new substations, providing shunt compensation, etc.. Each system improvement scheme has to be essentially tailor-made in nature to meet the specific requirements of the system conditions of the particular city, town or village chosen for loss reduction programme.

However, in addition to these conventional measures for loss reduction, it would be worthwhile to explore the possibility of adopting other cost effective measures (and equipment) which have found widespread use in the developed countries. In this context apart from advanced software for distribution planning studies, the induction of equipments like amorphous core transformers, series compensation for distribution lines, automatic voltage regulators, solid state energy meters etc. need to be considered. Apart from the above, the feasibility of gradual switching over from the existing LT distribution system adopted in India to HT distribution system (which is the appropriate technology for Indian systems) requires serious consideration.

5.1.5 Commercialization

The power supply industry in India as presently structured is entirely in the government sector except for a few licensees (like Calcutta Electricity Supply Co., Bombay Suburban Electricity Supply Co.) who are a legacy of the pre-independence days but continue to play an important role in the Indian power scenario The SEBs are expected to realize two objectives which are basically self-contradictory. The Indian Electricity Supply Act lays down that an SEB should be run as a commercially viable unit earning an annual surplus of at least 3 percent after meeting all its expenses At the same time, though not specifically mentioned in the Act, the State Electricity Boards are also required to fulfill an important social objective *via*, making electricity available to certain politically sensitive sectors like rural and agricultural consumers at highly subsided rates, quite often at rates much below cost of production Although initially the intention was that the government would compensate the SEBs to make up for the financial losses suffered by them on this account, barring a few states, majority of the State Electricity Boards are not being reimbursed It is because of these reasons that almost all the SEBs have been reduced to a state of virtual bankruptcy which is affecting their technical performance as well This in turn has resulted in unsatisfactory power availability position as well as poor quality of power supply to the consumers It is against this drawback that an acceptable solution has to be found to ensure the optimum utilization of the available generation resources to improve the quality of power supply and at the same time convert the SEBs into profit earning units without basically compromising the governments political commitment to supply power to the favoured categories of consumers at affordable rates. Present policy of the Government of India of opening up the

power sector for private participation offers a viable option to achieve a turn around in the power supply industry.

Recently the World Bank has indicated that in applying for loan assistance from the Bank for power projects, the utilities must satisfy the pre-condition that each operation of the utility (e.g. generation, transmission and distribution) should be commercially viable. Privatization of these operations is one option open to the utilities in satisfying the World Bank criteria. Although there are apprehensions that privatization of the distribution system could leave the utilities with the unremunerative rural distribution market, it remains to be seen exactly how the utilities will respond to the World Bank conditions.

The private sector is expected to play an important role in the power development of the country during the Eighth and Ninth plans, and a number of generation projects have already been identified spread all over the country for development by the private sector. Side by side with generation, implementation of the concept of private sector participation in the distribution of power is also under active consideration of the government. Under this concept, a private agency would make bulk purchases of power from the SEBs at certain selected grid points at mutually agreed rates, and sell it to consumers in a particular area allotted to it. As a matter of fact this type of arrangement already exists in the country e.g., Calcutta Electricity Supply Co. (CESC) in West Bengal, Bombay Electricity Supply and Transport Co. (BEST) in Maharashtra and Ahmedabad Electricity Supply Co. (AEC) in Gujarat since last four decades, and has been functioning very satisfactorily.

5.1.6 Conclusion

The impact of the excessive T & D losses in the Indian power system is two-fold. First, this is resulting in under-utilization of the total energy that is being generated, which is unpardonable considering the large energy shortages that the country is currently facing. The situation is further aggravated due to the fact that financial resource crunch is coming in the way of inducting additional generating capacities to the required extent. Secondly, the energy wasted due to excessive T & D losses is required to be compensated by setting up new generating stations (in all probability fossil fuel based thermal) with attendant environmental degradation problems due to emission of green house gases.

Past trends of investments in the power sector during the various Five-year plans shows that the capital outlays on T & D has not been commensurate with outlays on generation. These under-investments on T & D systems have resulted in high energy losses. A study on the investment pattern and the losses indicate that the investments made during the successive Five-year plans on T & D have been, by and large, only adequate to hold the T & D losses in the region of 22-23 percent corresponding to the capacity additions made during the various plans. In other words, for carrying out distribution

improvement works for reducing the losses below 23 percent level, additional funds (over and above the usual plan allocations) would have to be provided to the utilities.

Part B - Electricity Trade

5.2 Introduction

5.2.1 The Case For Trade

There are several reasons to more fully explore electricity trade in India. At the core, trade allows utilities to better manage their load so as to reduce costs. One popular transaction is the case where a summer peaking utility and a winter peaking utility trade electric power during their respective off-peak times. Coordination could also occur during the course of the day. Another type of load management activity, used in the course of the development of Canadian electrical supply, is where the utility builds capacity for export with its trading partner until the power is needed domestically. The exporting utility can reap the technical rewards, such as being able to operate systems at their optimal capacity, and operate continuously thereby allowing for consistent maintenance schedules. For the importer, it may allow capacity to be deferred until a later more cost-effective time.

The general benefits afforded through trade are presented in Table 5.4.

5.2.2 Types of Trade in India

Some of the major types of power transactions taking place in India's electric power sector are listed in Table 5.5.

The main philosophy underlying the planning of the Indian power systems has been that each state system be self-sustaining. The limits of this strategy have become evident, and as a consequence, efforts have and are being made to permit further power exchanges to realize the benefits of trade. One component of India's trade strategy is to review the practices and experiences of other countries, in this case, Canada's.

Table 5.4

Benefits to Trade

Reliability and Reserve Sharing: Contractual agreements for mutual emergency support between utilities can be used to improve total system reliability or to reduce the operating reserve margin requirement of each utility.

Load Diversity: When two electric utility systems in adjoining areas, or relatively close areas, experience peak loads at different times, the system loads are combined such that generating resources of both systems are better utilized.

Surplus Energy Sales: Energy which is not needed by a system at the time of its availability can be sold to another utility or in the case of hydraulic power, stored in another utility's reservoirs.

Economy Interchange: Economy interchanges occur where the incremental cost of generation on the supplying system of one utility is less than the incremental cost of generation for the purchasing utility. Larger, more efficient generating units or variations in fuel source can cause the generation costs on one system to decrease while the corresponding costs on another system are higher. Therefore, energy can be sold by one utility to another at a cost lower than the purchasing system can generate using its own equipment.

Unit Power Economies Of Scale: Interregional transactions that provide the opportunity for electric utilities to jointly plan the expansions of their systems and allow the installation of larger generating units, resulting in economic benefits to both electric utilities.

Coordinated Operations Scheduling: By coordinating the maintenance schedules of generating units, utilities can ensure that more efficient generating units are operated to their maximum limit.

Use Of Complementary Technologies: Many types of generation technologies complement each other. For example, during low water years, hydro units may provide peaking capacity, while thermal units supply base load energy.

Reduced Fuel Dependency: More efficient operations and increased use of alternative generation technologies made possible through increased inter-utility electricity exchanges can reduce the dependency on strategically important fuels such as oil for generating purposes.

SOURCE: U.S. Department of Energy and Energy, Mines and Resources Canada, *Canada/United States Electricity Exchanges* (Ottawa, Ontario: Minister of Supply and Services, May 1979), pp. 69-71.

Table 5.5

Major Power/Energy Transactions

Firm Exchanges: Take place when the selling system has surplus generating capacity and is in a position to supply power to a deficit system on a firm basis.

Emergency Exchanges (also known as Distress Exchanges): Cover import by a needy utility on account of loss of generation and/or outage of an important transmission facility.

Economy Exchanges: Cover exchanges among the interconnected systems to enable application of the concept of merit order generation on a regional basis.

Banking Transactions: Cover situations where one of the utilities has spare storage capacity in its hydro reservoirs to absorb split hydro/surplus thermal energy available in another utility.

Wheeling Assistance: Cover power exchanges between two systems which are not contiguous to each other by making use of the transmission facilities of a third intervening system.

Peaking Power Assistance: Occurs when the supply of power from a state system having surplus power during peak hours is sold to a neighboring system facing power shortage during peak load hours.

Reactive Power Assistance: Occurs through supply of reactive power (MVAR) by one system to another to meet its reactive power requirements.

Inadvertent Exchanges: Are actually unintended inter system power flows that take place due to the grid parameters prevailing at any given time, which keep on changing from moment to moment. These inadvertent power flows are a consequence of integrated operation of discrete power systems; however, the magnitude of these flows is somewhat high in the Indian Power system due to lack of availability of spinning reserve.

Unit Power: Power/Energy delivered from Jointly-owned & Central Government - owned Thermal/Hydro plants to the beneficiary states according to the shares allocated to them in these plants.

SOURCE: Tata Energy Research Institute

5.3 Canada's Experience with Trade

Electricity trade was fundamental to the early development of Canada's electric power system, and it will continue to affect the efficiency and evolution of Canada's electric power system in the years to come.[1] In fact, many hydroelectric developments were originally built using funds from long-term contracts with U.S. utilities. The first Canada-U.S. electricity interconnection--a 12,000 volt line--was completed in 1901. Table 5.6 depicts the major types of power transactions that currently exist in Canada.

5.3.1 Trade with the U.S.

Exports during the early period of electrical development were generally long-term firm contracts. An export contract with a U.S. customer, either an American utility or a major industrial electricity consumer, was essential to the construction of several early hydroelectric developments in Canada. In most of these cases, the firm that built and owned the generating plant in Canada was a subsidiary of the U.S. firm that accepted the power.

While Canada's initial exports to the U.S. were not large by present standards, they did account for a major share of Canada's early electricity production. By the 1920s, however, growth in domestic consumption had become the driving force for new hydroelectric developments and Canadian utilities were no longer dependent on the export market. After World War II, the increasing size and sophistication of electric systems contributed to an evolution in the nature of Canada-U.S. power trade. While firm exports still made a contribution to total Canadian sales to the U.S., a larger volume of electricity exports began to flow on a short-term basis as utilities on both sides of the border found that economy sales, emergency back-up, and seasonal exchanges enhanced the reliability and efficiency of their respective electricity systems.

By 1960, exports to the U.S. had fallen to less than 5 percent of total Canadian generation. However, in the late-1970s and 1980s, the volume of electricity exported by Canadian utilities rose again significantly. Most of this new wave of exports to the U.S. was of an interruptible nature as many Canadian utilities, burdened by excess capacity due to the demand slowdown of the early 1980s, aggressively promoted sales of economy power to neighbouring U.S. utilities. In the past several years, a number of utilities--Hydro-Quebec, B.C. Hydro, Manitoba Hydro and New Brunswick Power--have actively sought the type of firm, dedicated contracts that characterized

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[1]See Volume II of *Critical Issues in Electric Power Planning in the 1990s*, CERI Study No. 33 (Calgary, Alberta: Canadian Energy Research Institute, November 1989), for a detailed description of the historical development of Canadian electric power and the importance of electricity exports.

Table 5.6

Major Power/Energy Transactions

Firm: The supplier is obligated to deliver available power (capacity) and/or energy as scheduled for an extended period.

Non-Firm: Power (capacity) and/or energy available from surplus generating resources which is interruptible on very short notice.

Short-Term: Available power (capacity) and/or energy delivered for a specified period. Separate capacity and energy charges are usually applicable.

Unit Power: Power (capacity) and/or energy available from a specific generating unit or power plant delivered for an extended period, with availability normally dependent on the performance of the designated generating unit or plant.

Seasonal Diversity Exchange: Power (capacity) and/or energy exchanged between utilities with annual peak loads in different seasons, e.g. summer versus winter.

Off-Peak Energy: Energy normally provided during off-peak periods to supplement or conserve fuel storages (fossil or hydro) of the receiving system.

Emergency: Power (capacity) and/or energy provided on an hourly or daily basis to supplement the generating capability of the receiving system during periods of temporary capacity deficiencies.

Economy Energy: Energy delivered on an hourly basis to effect operating savings when the receiving party has adequate generation, e.g. fuel displacement.

Operating Reserve/Spinning Reserve: Excess generating capacity held available on ten minutes or less notice for use by another system to satisfy its operating reserve requirements.

Treaty Deliveries: Deliveries of energy required or permitted by treaty (such as the Columbia River Treaty).

Transmission Wheeling: Energy transported by an intervening party between a supplier and a receiver.

Storage Transfer: Electric energy transfer "banked" typically in the form of water in reservoir space of another electric utility in the expectation that equivalent electric energy will be returned at a later time.

Adjustment Transfer: An electric power/energy transfer to adjust electric power/energy account balances to compensate for services rendered, to deliver output entitlements, or to deliver upstream or downstream benefits.

SOURCE: U.S. Department of Energy and Energy, Mines and Resources Canada, *Canada/United States Electricity Exchanges* (Ottawa, Ontario: Minister of Supply and Services, May 1979), pp. 60-63.

early Canada-U.S. electricity trade. Firm exports have fluctuated between 17 and 46 percent, and interruptible exports have ranged from 47 to 83 percent, of total Canadian electricity exports over the 1960-1992 period. Hydroelectric power, the mainstay of Canada's exports to the U.S., represented 76.7 percent of the 26.2 TWh exported to the U.S. in 1992.

Table 5.7 reports the provincial sources of electricity generation for exports during 1992. Exports from Québec and British Columbia came almost entirely from hydroelectric stations. Exports from Saskatchewan were generated entirely from indigenous coal, while those from Ontario came primarily from thermal stations using imported U.S. coal. In New Brunswick, electricity exports were generated from nuclear, oil and coal sources. The hydro-based electricity exported by New Brunswick was purchased from Québec and resold. New Brunswick relied heavily on nuclear generation and base-load oil-fired capacity for its exports.

Table 5.7

Energy Sources of Electricity Exports
1992
(percent)

	Natural Gas	Oil	Coal	Nuclear	Hydro	Other[a]
New Brunswick	-	23	4	70	4	1
Québec	-	-	-	-	100	-
Ontario	-	6	74	15	2	2
Manitoba	-	-	1	-	95	4
Saskatchewan	-	-	100	-	-	-
British Columbia	7	-	7	-	86	-
Canada	2	3	11	11	72	1

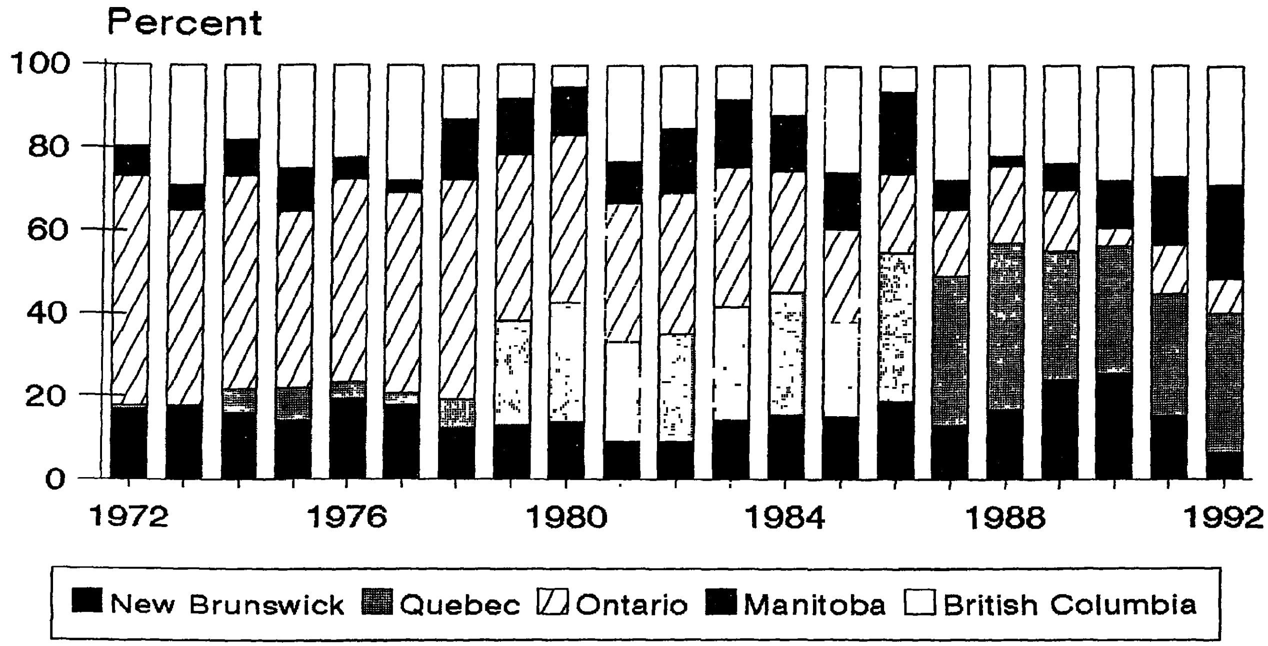
[a]Refers to U.S. electricity imports that are subsequently exported.

SOURCE: Energy, Mines and Resources Canada, Electrical Energy Branch, *Electric Power In Canada, 1991* (Ottawa, Ontario: Minister of Supply and Services Canada, 1992), p. 63.

Figure 5.1 displays the provincial shares of total Canadian electricity exports for the 1972 to 1992 period and shows Québec's dominant role in exports of electricity since the late 1970s.

Exports of Canadian electric power to the U.S. are summarized for 1992 in Table 5.8. While Canadian exports represent a very small percentage of total U.S. electricity demand, some U.S. states are very dependent on Canadian electricity sales. Exports to New England, for example, account for about 7 percent of this region's total electricity consumption.

Figure 5.1
Provincial Electricity Export Shares
1960-1987



SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada, Various Issues.

Table 5.8

Exporting Provinces and Importing U.S. Markets 1992[a]

Exporting Province	Importing Market	Quantity (MWh)	Value ($ '000)
New Brunswick	Maine	972 636	41 880
	Massachusetts	757 210	46 566
Quebec	Maine	918	66
	Vermont	1 785 155	77 061
	New England[b]	5 413 912	119 407
	New York	1 626 684	72 685
Ontario	Vermont	430	8
	New York	1 691 848	45 650
	Michigan	83 474	1 697
	Minnesota	26 426	1 635
Manitoba	Minnesota	3 876 447	62 156
	North Dakota	602 677	9 616
Saskatchewan	North Dakota	79 485	1 697
British Columbia	Washington	5 273 272	140 114
	Oregon	890 254	22 402
	Idaho	263 031	6 839
	Montana	17 091	341
	California	1 009 856	23 551
	Nevada	20 448	659
	Utah		
	Alaska	530	57
Canada	United States	24 391 784	674 086

[a]Excludes non-cash exchanges.

[b]The New England Power Pool (NEPOOL) coordinates electrical service to member utilities in New Hampshire, Maine, Vermont, Massachussets, Connecticut and Rhode Island.

SOURCE: Natural Resources Canada, Electrical Energy Branch, *Electric Power In Canada, 1992* (Ottawa: Minister of Supply and Services Canada, 1993), p. 64.

There are now over 100 international transmission lines in place to provide for Canada's international trade in electricity. Although most of these lines are quite small, there are 37 bulk power interties rated at 69 kV or higher, with a total transfer capacity of 18,900 MW.

5.3.2 Interprovincial

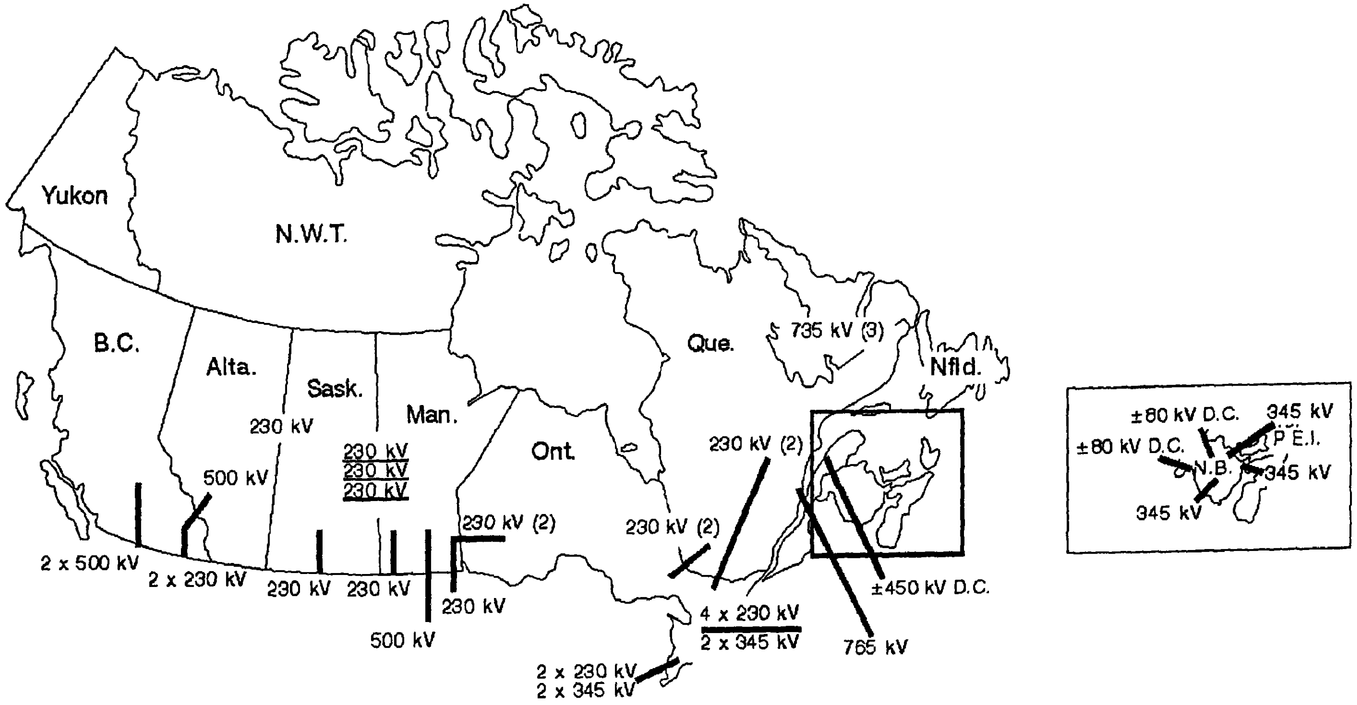
Historically, interprovincial electricity trade between utilities has occupied a much less prominent position than Canada's trade with the U.S. The first major electricity interconnection between Canadian provinces was only completed in 1928--a 230 kV connection between Ontario and Québec built almost 30 years after the first Canada-U.S. interconnection. In 1986, a 500 kV interconnection was completed between Alberta and British Columbia. In 1989, the completion of a 230 kV high-voltage, direct-current (HVDC) interconnection between Alberta and Saskatchewan established the first cross-Canada electricity grid (see Figure 5.2).

Interprovincial trade in electricity totalled 38,530 GWh in 1991 (7.9 percent of Canada's total generation), significantly above export levels to the U.S.(Figure 5.3). However, much of this is accounted for by a single transaction: the annual sale to Québec, since the early 1970s, of about 30,000 GWh of firm energy from Newfoundland's Churchill Falls hydroelectric development. Since this precedent-setting arrangement, there have been a few smaller, long-term interprovincial supply arrangements--most notably trade between Prince Edward Island, New Brunswick and Québec. However, Canadian utilities generally follow an independent approach to the development of electricity supplies, using out-of-province trade for only short-term or emergency backup. Reliability concerns, in-province employment spin-offs, and the narrow supply price differentials between Canada's provinces relative to those between U.S. and Canadian utilities, are the most commonly cited reasons for the independence in Canadian electric power planning. However, discussions portend greater levels of interprovincial trade between B.C. and Alberta, Manitoba and Ontario, and Newfoundland, Québec and Ontario in the future.

Annual Canadian interprovincial electricity trade for the 1960-1991 period is displayed in Figure 5.4. When the Churchill Falls hydro project began producing electricity, the volume of inter-provincial trade increased substantially as Newfoundland sold almost all of its output to Québec. In percentage terms, interprovincial electricity trade reached a peak in 1975, accounting for about 18 percent of total Canadian generation. However, by 1991, this figure had fallen to about 8 percent of total Canadian generation.

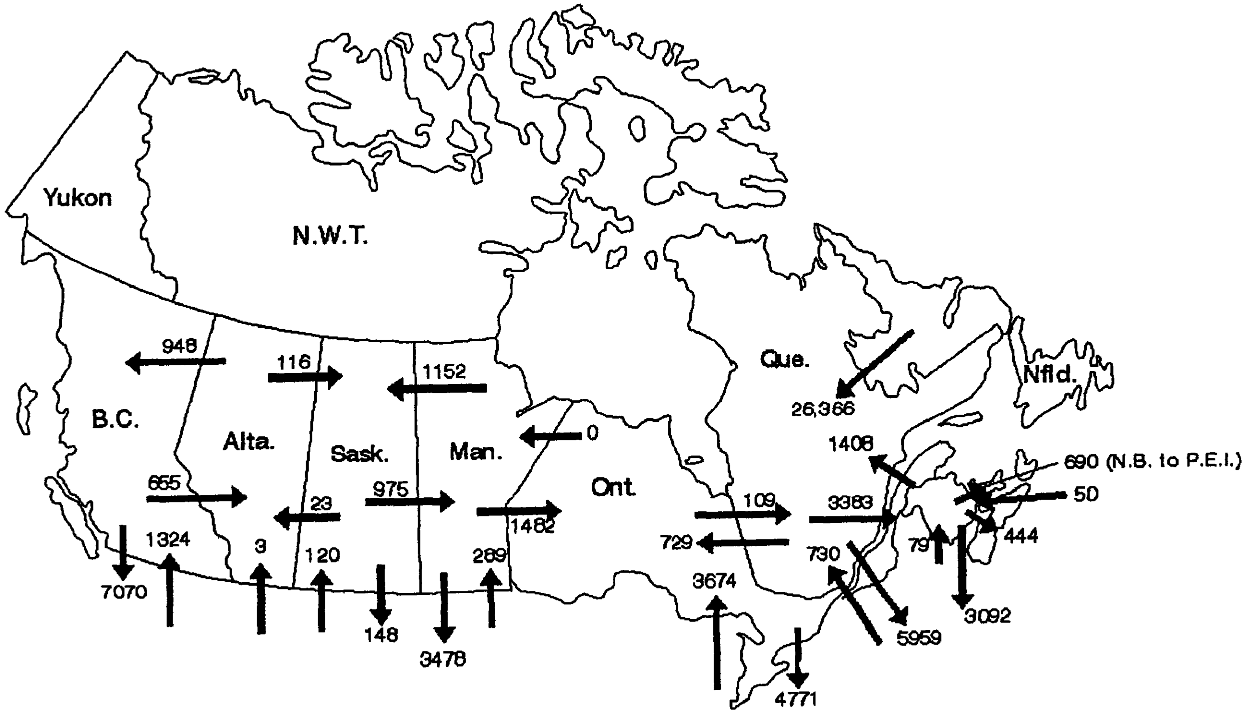
Currently there are 36 major provincial interties, with a total design capability of about 10,145 MW. This compares to the 36 bulk interties between Canada and the U.S. with a total transfer capability that is 86 percent greater than the transfer capability between Canada's provinces.

Figure 5.2
Major Provincial and Interprovincial Interconnections
1991



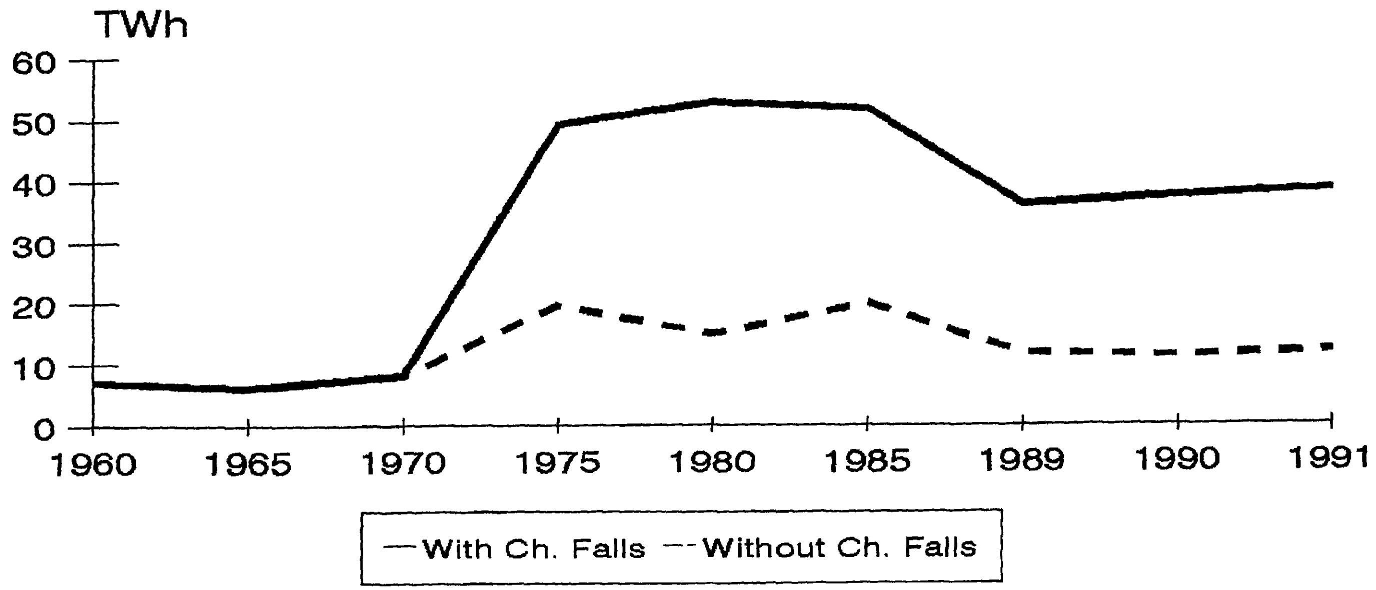
SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada, 1992, p. 73.

Figure 5.3
Electricity Trade, 1991
(GWh)*



SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada, 1991, p. 67.
*Includes non-cash exchanges.

Figure 5.4
Canadian Interprovincial Electricity Trade
1960-1991
(with and without Churchill Falls)



SOURCE: Energy, Mines and Resources Canada, Electric Power in Canada, 1991, p. 66.

5.4 Status of Trade in India

5.4.1 Development of Trade

The Indian electric power sector in its pre-independence era developed much as was the case in the early days of electric power sector development in Canada. Power supply in the country was mainly provided by the private sector; utilities met local demand through their own generation and T & D networks; and electrical networks were concentrated in urban centers.

In the post-independence era, the Government of India realized the necessity for unifying these isolated grids in order to bring the benefits of electricity to a larger section of the population and improve the quality of power supply. The Electricity Supply Act (1948), as amended periodically, paved the way for accelerating the pace of the unification of the isolated grids in the states.

The elements of the various Government of India trade strategies since India's liberalization include:

- the consolidation of local private electric utilities with the state;
- the regionalization of power planning to alleviate inter-regional disparities of natural resources;
- the development of a number of 132 kV and 220 kV inter-regional transmission links between regions;
- financial inducements to SEBs to encourage trade;
- the creation of central power generating stations to provide power to SEBs; and
- the creation of the Power Grid Corporation to construct, operate, and maintain trunk transmission lines and associated facilities and manage the commercial aspects of the sale of electricity from centrally-owned power stations.

Consolidation of the state power grids took place during the First and Second Five Year Plan periods. The development of the transmission system in the individual states during the Third Plan was largely at the 66 kv and 132 kv level. Development of 220 kv systems has only recently been initiated.

In the mean time, in order to take care of the uneven nature of the distribution of natural resources (i.e., hydro resources, fossil fuels and nuclear fuel across the country), the Government of India shifted power planning from the state level to the regional level. This conceptual change in power planning was introduced in the Third Plan. In 1964, Regional Electricity Boards were set up entrusted with the task of ensuring and facilitating the integrated

operation of the regional grids. For the purpose of power planning, the country was divided into five regions: **Northern Region** (Punjab, Haryana, Jammu & Kashmir, Rajasthan, Uttar Pradesh, Delhi, & Chandigarh); **Western Region** (Madhya Pradesh, Maharashtra, Gujarat and Goa, Daman & Diu and Nagar Haveli); **Southern Region** (Karnataka, Kerala, Tamil Nadu, Andhra Pradesh, and Pondicherry); **Eastern Region** (West Bengal, Bihar, Orissa & DVC system); and **North- Eastern Region** (Assam, Meghalaya, Mizoram, Arunachal Pradesh, Nagaland, Manipur and Tripura).

Once a more equitable allocation of resources had been established through regionalization of the electrical supply, the next step was to develop the transmission networks to transmit the power between regions and states. A number of such inter-regional links, mainly at 132KV and 220KV levels, were constructed by SEBs with financial assistance from the Central Government. At present, there are fifteen 220 kV inter-regional tie lines in place having a transmission capacity in the order of 1000 MW. Two 400 kV inter-regional ties are in place; one is equipped with a DC back-to-back terminal. Another three 400 kV inter-regional tie lines are under construction and likely to be commissioned in the next 4 - 5 years. Thus, power transmission capacity of about 1500 MW would be available for electricity exchanges at the 400 kV level. Table 5.9 gives the length of inter-state/regional lines for both existing lines and lines under construction. The overall picture of the inter-regional lines at 220 kV and 400 kV is shown in Figures 5.5 and 5.6.

For promoting inter-state and inter-regional energy exchanges between state utilities, the Government of India encouraged the construction of inter-state/regional links by advancing interest-free loans to the SEBs. This accelerated the process of formation of compact regional grids. To pave the way for an all-India national power grid, the central government set up regional power stations, owned and operated by the Central Government viz., National Thermal Power Corporation (NTPC), National Hydro-Electric Power Corporation (NHPC), Neyveli Lignite Corporation (NLC), North Eastern Electric Power Corporation (NEEPCO), etc.. These institutions have greatly facilitated trade through the formation of compact regional grids. In particular, the NTPC and the NHPC, which came into existence in 1976, were entrusted with the task of setting up large regional power stations and the constituent states were allocated specified shares in the generated power from these stations through its associated transmission system.

In 1989, the Power Grid Corporation was setup and entrusted with the task of construction, operation and maintenance of trunk transmission lines and associated facilities (including load dispatching stations) and also for managing commercial aspects of sale of energy from the Central Government owned power stations and inter-regional energy exchanges.

Table 5.9

Length of Inter-State/Regional Transmission Lines[a]
(As of June 30, 1993)

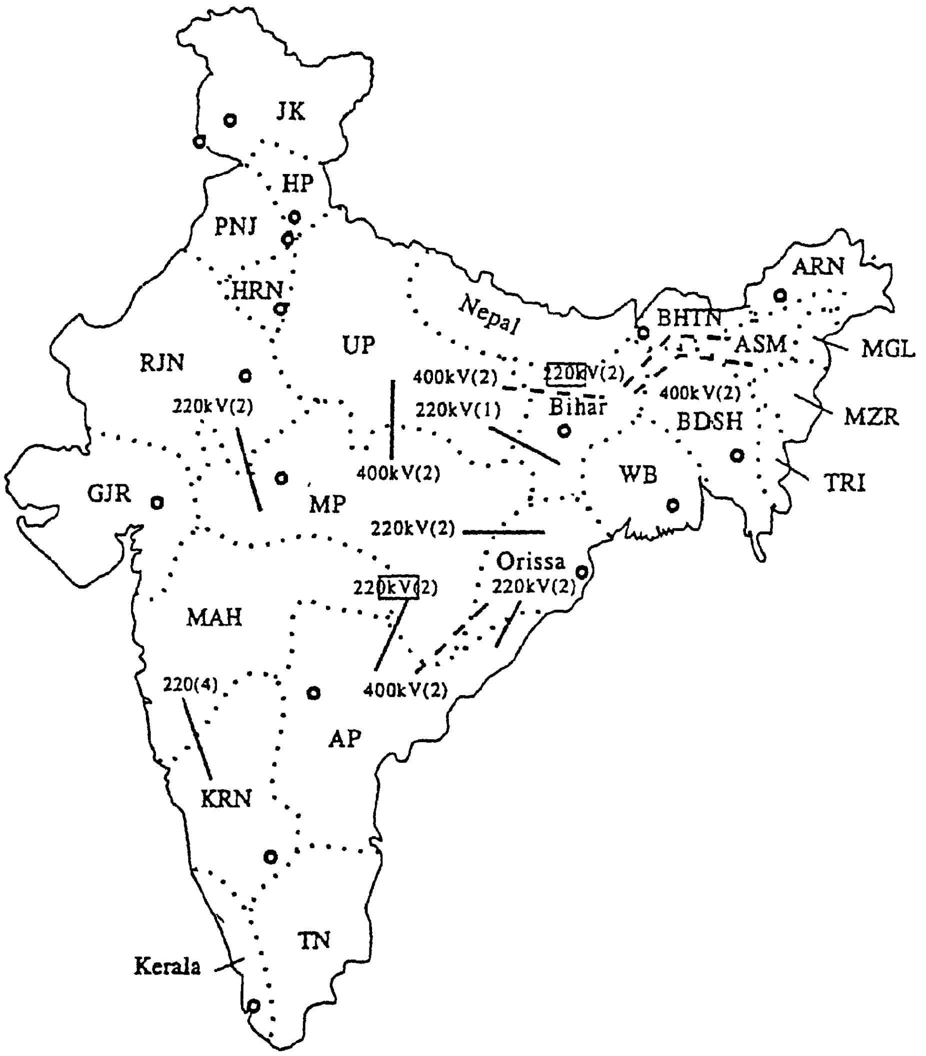
Existing	132kV	220kV	400kV	Under Construction 132kV	Under Construction 220kV	Under Construction 400kV
A. Inter-State Lines						
Northern Region	153	860	-	-	-	-
Western Region	-	865	-	-	-	-
Southern Region	50	1490	-	-	-	-
Eastern Region	-	436	375	-	42	-
North-Eastern Region	556	-	-	135	-	-
Total	759	3651	375	135	42	-
B. Interregional	-	1349	-	-	797	3236
C. International	-	216	-	-	-	-

[a]All lengths are in kilometres.

SOURCE: Tata Energy Research Institute, July 1994.

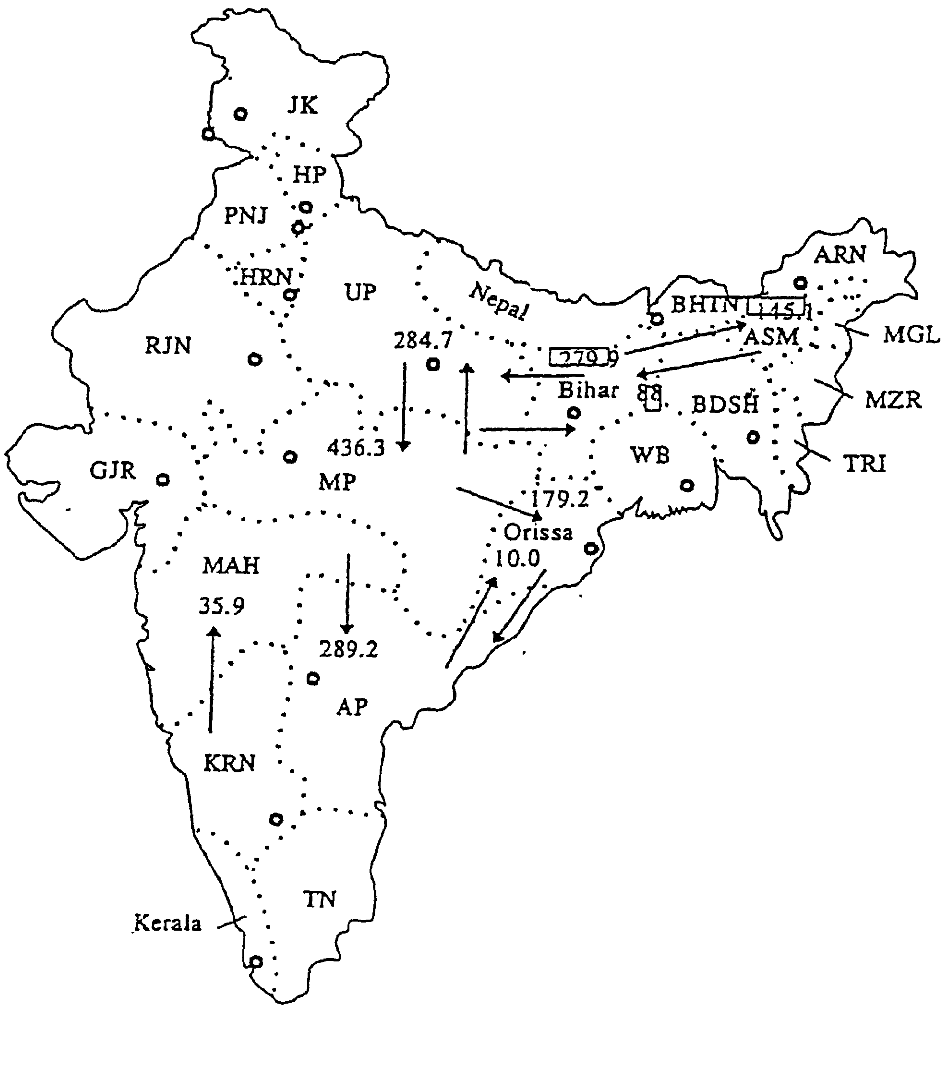
NOTES: (1) Transmission lines associated with National Thermal Power Corpoation(NTPC)/National Hydro-electric Power Corporation(NHPC) generation projects and required for delivery of allotted shares from these projects partner states are not included in the table; and (2) The International transmission lines mentioned above, refer to the lines from Chukha Hydro-electric project in Bhutan to Birpara in India.

Figure 5.5
Major Interregional Interties
(existing and proposed - 1993)



SOURCE: Tata Energy Research Institute (July 1994).

Figure 5.6
Interregional Electricity Exchanges in 1992-1993 in MU



SOURCE: Tata Energy Research Institute (July 1994).

5.4.2 Status of Trade in India

The types of exchanges actually taking place in India can be characterized as: (i) *emergency exchanges* during systems contingencies; (ii) *firm exchanges* which are committed supply from a surplus state to a deficit state system; and (iii) *inadvertent exchanges* which are unscheduled exchanges. Economy exchanges, which are based on consideration of incremental cost of energy of various power stations in the system, are not generally used in the Indian power system. Figure 5.6 shows the inter-regional electricity exchanges that took place in 1992-93.

5.4.3 Future Prospects for Trade

Installed generating plant capacity, which was 42,400 MW in 1984-85, is likely to increase to 67,000 MW by the end of the Eighth Plan (1990-95). According to the Central Electricity Authority (CEA) assessment (September 1991), the country's power system would need additional power plant capacity of the order of 142,000 MW along with matching T & D facilities by 2006-07 (terminal year of Tenth Plan). Considering the magnitude of expansion and the size of the power system together with the corresponding expansion of the transmission and load dispatching facilities, the scope of inter-state/regional energy exchanges could be expected to expand considerably.

One of the essential requirements of integrated operation of power systems is the availability of adequate transmission facilities that permit free interchange of power between different power systems. Steps are being taken to remove the existing deficiencies to greater regional trade within India by providing the necessary 400 kV interties on a priority basis. The present position of 400 kV inter-regional links is as follows.

(i) Vindhyachal (M.P.) - Singrauli (U.P.) connecting Western and Northern regions - existing and provided with DC back-to-back terminal at Vindhyachal.

(ii) Ramagundam (A.P.) - Chandrapur (Maharastra) connecting Southern and Western regions - construction completed recently and action initiated for setting up DC back-to-back terminal at Chandrapur.

(iii) Bongaigaon (Assam) - Malda (West Bengal) connecting North - Eastern and Eastern regions planned for construction (target: 1998-99).

(iv) Mau (U.P.) - Biharshariff (Bihar) connecting Northern and Eastern regions - planned for construction (target: 1998-99).

(v) Jeypore (Orissa) - Gazuvaka (A.P.) connecting Eastern and Southern regions - planned for construction (target: 1998-99).

In addition to the above links, the following 400 kV inter-regional tie-lines could be considered which would enhance grid reliability and would also be helpful for mutual electricity exchanges:

(vi) Korba (M.P.) - Rourkela (Orissa) - connecting Western and Eastern regions.

(vii) Kota (Rajasthan) - Nardipur (Gujarat) providing a second link connecting Northern and Western regions.

However, all the above links will have to be equipped with DC back-to-back terminals to establish effective inter-regional connections permitting free mutual power exchanges.

In order to expand the scope of electricity trade further in the coming years, it would be necessary to devise a suitable tariff structure for inter-system energy exchanges which would be attractive to all participating systems and that would enable optimal operation of the regional systems. The necessary administrative structure at the regional and national level has already been created to promote effective integrated operation in the form of Regional Electricity Boards and the Power Grid Corporation.

5.5 Issues of Concern

While there are clear gains to trade, India has been handicapped both due to lack of adequate inter-state/regional transmission facilities and the absence of commercial guidelines governing inter-system energy exchanges.

5.5.1 Technical Considerations

Generally speaking, planning for power system development in India has suffered from far greater emphasis and funding on new generating capacity rather than transmission, based on the assumption that some patchwork of the existing transmission network would meet requirements. This has resulted in development of a transmission system that is barely adequate for meeting normal operating conditions, and lacks redundancy to take care of contingencies.

Indian power systems are generally planned for withstanding the following contingencies.

- Power stations: one unit under planned maintenance and unplanned outage of any one the largest sized units.
- Unplanned outage of one circuit of any of the transmission lines emanating from a sub-station or a power station.

As regards facilities for inter-state energy exchanges, the isolated power systems at the state levels have been integrated to form composite state power grids with fairly strong inter-ties connecting the state systems in the

individual regions. The transmission links interconnecting the different regions, however, are rather weak, being mostly at 132 KV and 220 KV level with limited transmission capacities. Hence, steps have been initiated to establish strong inter-regional ties among the different regions, and 400 KV interconnections have been established between Northern and Western and Western and Southern regions. In addition to these, interties connecting Northern and Eastern regions and North-Eastern and Eastern regions have been planned for construction during the next 5 to 10 years.

Another factor standing in the way of inter-regional electricity trade is the difficulty in interconnecting the regions in AC mode, due to the fact that the operating grid frequencies of the different regional grids are somewhat different from each other. This is primarily because of power shortage conditions prevailing in the Indian power systems which forces them to operate their systems at frequencies below the standard frequency of 50 cycles per second (c/s). Since the extent of power deficit varies from region to region, the extent of frequency deviation (from the standard frequency of 50 c/s) is different for different regions. Under these conditions, the only way to interconnect the regions is to establish HVDC interties with back-to-back DC stations at the interconnecting points. For example, the Northern-Western inter-regional link, connecting Singrauli Thermal Station (N.R.) and Vindyachal Thermal Station (W.R.), has a DC back-to-back terminal at Vindyachal. The Ramagundam-Chandrapur inter-regional link connecting Southern and Western regions will also have DC back-to-back facilities.

Yet another factor limiting the extent of power exchanges is the lack of adequate load dispatching and communication facilities, without which it is difficult to operate a complex interconnected system. While a start has been made in establishing load dispatch stations at the regional level, matching facilities at the state level have yet to be set up. As regards communication facilities, Indian power systems are still largely dependant on primitive facilities like power line carrier communication (PLCC) and unreliable public telephone systems.

5.5.2 Commercial Considerations

Another factor limiting the extent of electricity trade in India is the lack of well-defined norms and guidelines in regard to inter-system energy exchange transactions. Two rather peculiar results have transpired on occasion as a consequence. Cases exist where surplus-power stations have reduced generation rather than sell surplus power to deficient-power stations because of the uncertainty of the tariff. At the other extreme is the case where a power station refuses to reduce its generation even when there is no demand, resulting in wasteful high frequency operation which sometimes even leads to wastage of water in run-of-river hydro stations and also results in unwanted import of energy. These perverse examples unquestionably lead to system inefficiency.

Another irritant in electricity trade in India has been the absence of standard commercial practices in regard to transactions involving the 'wheeling' of power. In an integrated system, energy has sometimes to flow through the transmission network of a utility other than that of the donor/recipient system. This type of transaction involves two issues:

(i) the rate at which the utility whose transmission systems is used for the benefit of the other utility is to be compensated; and

(ii) determination of the incremental transmission losses payable to a wheeling utility.

In order to improve the prospects for electricity trade, apart from certain technical measures, it will be necessary to formulate well-defined commercial guidelines and a rational tariff structure to encourage the selling and buying of energy for mutual benefit. Suitable measures have also to be devised to discourage high-frequency operation of the grid.

5.6 Conclusions

The lack of adequate transmission facilities and absence of well-defined commercial principles has prohibited the efficient development of trade in India. As a first step towards India's long term strategy to encourage trade, there must be: (i) a reinforcement of intra-state transmission facilities and strong interties between regional systems--preferably at the 400 kV level equipped with back-to-back direct current terminal stations, and (ii) development of consistent, clearly defined commercial principles and guidelines for power exchanges.

Chapter 6

ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

6.1 Introduction

India is faced with growing energy requirements to support its economic development. Demand for electricity increased at a compound annual rate of nine percent during the period 1980/81 to 1992/93. Income elasticity, measuring the percent growth in electricity demand due to a one percent increase in economic activity, measured 1.57 over the period. While there have been significant efforts on part of electric utilities to enhance supply to meet this demand, both peak and energy shortages persist in many parts of the country. In 1991/92, the country experienced an overall energy deficit of 8.5 percent and 17.7 percent of the peak demand remained unserved. Although the per capita consumption of electricity is low (253 kWh in 1990/91), the energy intensity of Indian industries--which account for nearly 50 percent of the total electricity consumption--is very high. Several reports have indicated a potential for energy efficiency gains of 20-30 percent in the industrial sector. According to the official forecast for electricity demand carried out by the 14th Electric Power Survey of the Central Electricity Authority (CEA), demand for electricity is expected to increase at a rate of eight percent until the year 2011/12.

Electric utilities in India have in the past adopted the traditional approach of adding new supply capacities to meet the growing demand for electricity. The installed power generating capacity and gross generation increased at a compound annual rate of nine percent and 10.2 percent, respectively, during the period 1980/81 to 1992/93. This growth has been achieved largely through investments made by the government in the successive Five Year Plans. The Plan allocation for the power sector has varied between 17 and 18 percent of the total Plan outlay, and in absolute terms, the outlay has been doubling every ten years. In the Eighth Plan (1992-97), 24 percent of the total outlay has been allocated for the power sector, of which 62 percent has been earmarked for adding new generation capacities. The balance of the resources are allocated for transmission and distribution (T&D) network expansion (28 percent), rural electrification (5 percent), renovation and modernization (two percent), and miscellaneous (three percent).

The future growth of the power sector will, however, be constrained by two crucial factors. First, constraints on financial capital availability will prevent capacity additions required meet all the demand. Compared to the estimated requirement of Rs 1,280,000 crores for power sector development in the Eighth Plan, the Plan allocation has been only Rs 79,589 crores. Consequently, the capacity addition program was scaled down from 38,000 MW to 30,000 MW, and was further reduced to 23,000 MW. Second, growing efforts to limit environmental impacts of energy production

and use will require India (like any other developing country) to come up with strategies that can limit environmental impacts in their national development policies.

End-use efficiency improvement and demand-side management (DSM), therefore offer new hope to Indian utilities to bring the demand and supply of electricity closer into balance. Utilities in the United States, Canada and several European countries are meeting (or saving) more and more of their new demand through DSM and energy efficiency measures. The U.S. Electric Power Research Institute (EPRI) estimates that DSM is likely to provide 20 percent of the additional summer peak requirements in the U.S., in the year 2000. A recent study carried out by the U.S. Office of Technology Assessment estimates that overall electricity savings of 50 percent are possible in developing countries with currently available energy efficient technologies. Further, these technologies would provide financial savings to individual consumers over the lifetime of the equipment of more than 25 percent.

There has been growing recognition of the importance of energy efficiency in India's electricity sector. The Ministry of Power (MoP) is the nodal agency for energy conservation in the country. The Energy Management Centre (EMC), an autonomous body under the MoP, was set up in 1989 to coordinate initiatives and activities on energy conservation. Several state electricity boards (SEBs) have also set up Energy Conservation Cells, some of which have been assisting industries in conducting energy audits. Several reports have attempted to estimate the potential for energy conservation in various consuming sectors and have also identified various energy efficient technologies (EETs) for important end-uses. The National Energy Efficiency Program (NEEP) of the Government of India (GOI) has targeted savings of about 5000 MW to be realized by the end of the Eighth Plan through both demand (2750 MW) and supply side (2250 MW) efficiency improvements. In terms of government policies, there are special tax incentives affording 100 percent depreciation for energy efficient equipment in the first year, subsidies for energy audits, reduced customs duty for selected control equipment for managing energy use, and so on

In spite of these efforts, substantial efficiency gains are yet to be achieved. There are a number of technical, cost, institutional, and information related barriers that have constrained the actual implementation of energy efficiency and DSM in India. Absence of appropriate market conditions and government policies, lack of information, lack of consumer confidence in new technologies, capital scarcity, or simply a rather limited interest in energy costs and savings have all contributed to slowing the introduction of energy efficient technologies.

This chapter attempts to estimate the realistic potential for energy efficiency in various end-uses and electricity savings potential in India, reviews

the initiatives undertaken by utilities, government and the private sector in promoting energy efficiency and DSM, and identify barriers in implementing efficiency programs. Recommendations for DSM in India are premised on the experience of utilities in North America and Canada.

6.2 Demand-side Management Defined

Demand-side management is used to describe the actions of a utility, beyond the customer's meter, with the objective of altering the end-use of electricity - whether it be to increase demand, decrease it, shift it between high and low peak periods, or manage it when there are intermittent load demands - in the overall interests of reducing utility costs. In other words DSM is the implementation of those measures that help the customers to use electricity more efficiently and in doing so reduce the customers' bill as well as the utility costs. DSM can be achieved through:

- improving the efficiency of various end-uses through better housekeeping, correcting energy leakages, system conversion losses, etc.;
- developing and promoting energy efficient technologies; and
- demand management through adopting soft options like higher prices during peak hours, concessional rates during off-peak hours, seasonal tariffs, interruptible tariffs, etc..

DSM, in a wider definition, also includes options such as renewable energy systems, combined heat and power systems, independent power purchase, etc., that enable the utility to meet the customer's demand at the lowest possible cost

Often the terms energy efficiency and DSM are used interchangeably. However, it is important to point out that DSM explicitly refers to all those activities that involve deliberate intervention by the utility in the marketplace so as to alter the consumer's load profile. Energy efficiency is used in an all encompassing sense and includes any activity that would directly (e.g. energy audit) or indirectly (e.g. tax incentives) lead to an increase in energy efficiency. To make this distinction precise, a program that encourages customers to install energy efficient lighting systems through a rebate program would fall under DSM. On the other hand, customer purchases of energy efficient lighting as a reaction to the perceived need for conservation is not DSM but energy efficiency gains.

6.2.1 Importance of DSM

Demand-side management is now a multi-billion dollar, world-wide industry. In 1991, U.S. and Canadian utilities alone budgeted some $2 billion for DSM programs.[1]

Much of the attention to DSM in North America is devoted to conservation and load reduction; in fact, utilities not offering these programs have become the exception rather than the rule. To date, over 500 utilities have offered greater than 1000 programs.[2] The Electric Power Research Institute (EPRI) has estimated that strategic conservation will account for 69 percent of the planned peak demand reduction from utility programs through the year 2000.[3] In Canada, utilities expect that DSM savings will amount to 12,565 MW, 60 percent of which is to come from strategic conservation programs.[4]

Three key issues drove the electricity sector to embrace DSM: (1) a strong lobby from environmental groups to reduce the pollution impacts of electricity generation, distribution, and transmission activities; (2) a looming capacity crisis in many jurisdictions which, for reasons ranging from environmental concerns to financing capabilities and *ex poste* prudency hearings, was unlikely to be met by expanded coal and nuclear generation; and (3) customer calls for cheaper rates, as the industry turned from one with declining production costs to one of increasing costs.

The *first-generation* DSM programs implemented by electric utilities were low-cost, easy-to-implement programs such as residential audits, simple information dissemination, direct load control, and rate design. During the early 1980s, residential weatherization programs became widespread in the United States. More recently, particularly in California, the North Eastern and North Western U.S., Ontario, and British Columbia, utilities have begun to implement comprehensive programs--*second-generation* programs--incorporating packages of energy-efficiency measures and multiple marketing and delivery techniques.

6.2.2 The Virtues of DSM

As experience with DSM has grown, its many advantages have surfaced. For instance, DSM can:[5]

Reduce utility costs: Kilowatt demand reductions through DSM programs can be provided at lower cost per kW than capacity expansions; they therefore reduce utility costs and investment needs.

Keep rates low: Following from the reduction in utility costs, rates can be lower than they would have been had the utility not undertaken such programs.

Reduce customer bills: DSM programs lower customer's electricity bills. These customers now have more income to spend elsewhere in the economy.

Increase utility revenues: Evidence suggests that DSM programs do have value to electricity customers, value which they are willing to pay for.

North American energy-service companies (those companies whose singular interest is to provide DSM programs) have shown that these programs can provide returns in the order of 20-40 percent. Regulated investor-owned utilities in North America are being allowed to capture a portion of these returns through regulatory incentive mechanisms. Thus DSM has been shown to increase utility revenues.

Generate greater employment opportunities: DSM is far more labour-intensive than conventional supply-side options. For example, in a comparative study of B.C. Hydro's DSM program relative to a hydro-electric facility, the net employment effects in favour of DSM were estimated at 11,859 person-years.[6]

Build relationships with trade allies: A useful aspect of energy-efficiency programs is the development of close working relationships with trade allies--notably builders, manufacturers, distributors, and financial institutions. Stronger relationships can increase sales opportunities for all parties, and reduce DSM implementation and administration costs for the utility. Through DSM, electric utilities have helped reduce the additional costs of manufacturing high efficiency equipment and constructing facilities for builders and manufacturers, making electrotechnologies and electrically-heated homes more attractive and offering increased sales for all.

Working associations between the utility and its trade allies can also lower utility costs in the provision of DSM programs. Builders, manufacturers, and distributors are often eager to participate with utilities who have direct contact with potential buyers of their products. Because of this, they are willing to share DSM program costs, often providing the incentives themselves or aiding in advertisement costs.

Financial institutions have also become 'trade allies' in the implementation of DSM programs. Electric utilities and banks often form partnerships to provide loans to utility customers for the purchase of efficient electrotechnologies. The utility has direct contact with their customers, and the bank has the expertise to administer the loans. This partnership also reduces utility costs in program implementation.

Enhance public relations: Electric utilities have found that energy-efficiency programs assist their public relations. Customers feel the utility is doing its part, through the implementation of DSM programs, to ensure the sustainable development of the economy.

Strengthen the electric utility's competitive position: Through the implementation of DSM programs, utilities improve customer service and relations and, because of this, increase their competitive position.[7]

Strengthen the competitive position of the utility's industrial customers: Many small- and medium-sized companies do not have the resources to devote to seeking out innovative technologies because they are too busy trying to stay in business in an increasingly competitive market. Electric utilities have found that through DSM they can provide their expertise on electrotechnologies and associated services to help their customers increase their competitiveness. This working relationship is seen to increase customer loyalty.[8]

Increase information about customers: While gathering the customer end-use information necessary to design DSM programs, the utility has the opportunity to build a more complete understanding of the customer which can be used not only to design DSM conservation and load reduction programs but also increase electricity sales.

Increase customer satisfaction: Many utility customers like DSM programs: they enjoy the reduced energy bills, the services such as installation of new, high-tech equipment, and the increased comfort that often comes with the implementation of DSM programs. For example, a retrofit program to reduce electricity use such as window caulking may reduce drafts from the window.

Increase planning and operational flexibility: Conventional electric generating facilities such as hydro and coal-fired power plants have long lead times. Moreover, power generating facilities are often more efficient as the size increases. Both the long lead times and economies of scale for electricity generation tend to mean supply does not always meet demand: the electric utility will typically have too much capacity available for its customers at any one time. In contrast, DSM programs can be put in place and be operational in a matter of months with almost limitless program sizing possibilities. The utility can, therefore, more closely meet the electricity service needs of its customers--not only kWh, but how these kWh are used.

Reduce pollution: DSM reduces the need for power generation facilities which will normally translate into less pollution.[9]

It is for all of these reasons that DSM has attracted the attention of electric utilities.

6.2.3 Whose Business Is It Anyway?

In most developed countries, particularly the U.S. and Canada, DSM programs have been initiated by utilities since this has proven to be a more cost effective means of meeting new demands than capacity expansion. In several European countries, pressures to limit environmental impacts of power generation and supply have pushed the utilities to adopt DSM and energy efficiency measures. More and more utilities are, therefore, today

practicing Integrated Resource Planning (IRP), where both supply and demand side options are evaluated in an integrated framework to develop a least cost plan to meet the demand for electricity.

There are four major players involved in any DSM program--end-user, government and the utility, manufacturer of energy efficient equipment, and private sector such as energy service companies, industry associations, consumer forums, etc.. The multiplicity of players sharing costs and benefits of energy efficiency often results in each one of them waiting for the other to take the lead The manufacturers of EETs complain of lack of market, end-users complain of high comparative costs and non-availability of EETs, and the government is willing to go only so far in providing concessions on taxes, duties, etc., preferring market forces to play the leading role. In the final analysis, it is energy efficiency that has lost out.

Under perfect market conditions, where there is a competitive market for goods and services and prices are not distorted due to economic and social considerations, energy efficiency gains would have been achieved. In most developing countries, this is not the case and therefore utility intervention is important to provide the necessary impetus to promote energy efficiency and DSM. However, all actors--utility, government, users and trade allies--have an important role to play in the success of any DSM program. While the manufacturers can make energy efficient technologies available, the government and the utilities are the facilitators who can and should assist in persuading the end-user in making the final decision.

6.3 North American Experience[10] in DSM

The success of North American utility ventures into DSM can be attributed to four 'simple' features: (i) well designed programs; (ii) IRP; (iii) partnerships, and (iv) standards.

6.3.1 Success Stories

The U.S. utilities most active in DSM have been those in New England (e.g. Central Maine Power, the New England Electric System, and Northeast Utilities), California, the Pacific Northwest (e.g. the Bonneville Power Administration, Seattle City Light, and Puget Power), and Wisconsin. In Canada, Ontario Hydro and B.C. Hydro have developed some successful end-use efficiency programs in the last several years. Other Canadian utilities, such as Hydro-Québec and TransAlta Utilities, have been more progressive in the area of DSM rate incentives.

There are many examples of outstanding DSM initiatives undertaken in North America. These programs have achieved high participation rates and high electricity savings, and have been provided at a lower cost than conventional supply-side options.

In the discussion that follows, these initiatives are categorized according to cost: from lower cost initiatives such as the promotion of electrotechnologies, to the more moderate-cost, new construction programs, and finally the more expensive retrofit programs.

6.3.1.1 Information

Common to all successful DSM programs are information campaigns. All utilities offer a variety of information packages or educational outreach programs such as brochures, newsletters, media advertising, video tapes, seminars, feedback to customers on their energy bills, and energy rating and labelling programs. The advantage of these programs is that they tend to be low-cost and flexible, with the potential to reach a large number of customers quickly. The main disadvantage is that they do not necessarily lead to action, and it is often difficult to link them directly to energy savings actually achieved. In some cases, information is delivered along with an incentive program, so that there is a problem separating out the impact of the informational component.

6.3.1.2 Electrotechnologies

Rebate programs promoting energy-efficient equipment, such as household appliances, lighting, and motors, have been the single most popular DSM activity undertaken by electric utilities. A survey conducted for EPRI in 1986-87 identified 59 utilities offering rebates for residential, commercial, and industrial energy-saving equipment.[11]

Of the more successful appliance rebate programs for the residential markets, energy savings have reached 4-8 percent with cumulative participation rates of 25-80 percent, at costs of 1-2 cents/kWh.

Lighting programs in the residential sector usually have cumulative participation rates that range between three to ten percent, although more aggressive programs have recorded participation as high as 26-57 percent. The savings and costs for residential lighting programs are not currently available. A review of over thirty lighting rebate programs for the commercial and industrial markets revealed cumulative participation rates ranging from less than one percent to about 20 percent, with a median of three percent.[12] The utility costs were in the range of 1-2 cents/kWh for energy savings of 2-3 percent. The highest rates were typically found in small pilot programs that had been vigorously marketed.

In a review of fifteen motor programs, Steven Nadel of the American Council for an Energy Efficiency Economy (ACEEE) found typical participation rates of less than three percent of motor purchases.[13] Average energy savings of 5-10 percent were reported for selected programs. Reasons for low participation may include reluctance on the part of the customer to temporarily shut down production lines, a tendency for customers to rewind

worn-out motors rather then replace them, and low rebate levels in some programs.

6.3.1.3 New Construction Market

It is common to single out the new construction market, since strategic conservation measures for that market represent potential *lost opportunities*. These refer to measures which offer long-term, cost-effective electricity savings, but which may be lost or rendered uneconomic if they are not exploited at the time of construction. Many conservation measures can be installed in new buildings for a relatively small incremental cost over and above standard construction practices. Retrofitting these measures at a later date could prove much more costly or technically unfeasible.

Residential new construction programs can range from simple information programs to comprehensive service packages that include financial incentives, education, and technical training for building owners/managers, architects, developers, and other professionals. The most common types of programs to date have been energy rating and labelling programs.

Typically, energy rating or labelling programs certify that a home meets a specified level of energy efficiency or that it contains specific energy-saving features. To date, the participation rates for the popular HERS (Home Energy Rating Systems) have ranged from two to 100 percent, averaging 40 percent. Measured savings for a sample of four utilities showed 30-50 percent reductions in annual electric space heating use.[14]

In the residential market, several utilities provide financial incentives to the builder or homebuyer, in order to reduce the up-front purchase price of an energy-efficient home. The largest incentive payments have ranged between $1000 and $3000, primarily for home demonstration programs. Some programs provide much smaller incentives of $100 to $200, mainly to cover the builder's advertising costs. However, few utilities offer only incentives. Another technique employed is utility arrangements with local banks and mortgage companies to make energy-efficient homes eligible for higher loans (i.e. through the allowance of higher debt-to-income ratios).

Information on net energy savings from comprehensive programs is not widely available. Central Maine Power conducted an evaluation of its Good Cents Home Program in 1990. The program was found to produce an average 22 percent reduction in energy use for participating electrically-heated homes.[15]

Comprehensive programs for new commercial and industrial buildings combine technical assistance with incentive features. Incentives may be offered to address both the incremental construction and equipment costs of an energy-efficient building and the additional design time taken. Given the

pilot or start-up nature of programs to date, participation rates appear low. Some utilities (e.g. Northeast Utilities), however, are targeting their programs for over 60 percent of new commercial buildings after five years.

6.3.1.4 Retrofit Programs for Existing Buildings

Unlike the potential lost opportunities of new construction, energy efficiency in existing homes, buildings, and industrial facilities can be modified at any time. Programs to promote strategic conservation in existing buildings cover a wide range, from simple information programs to comprehensive programs where the utility offers energy analysis, financing, and installation of cost-effective efficiency measures.

As a stand-alone program, energy audits have not been very successful in the residential market. However, they are usually used to get more information on the customer's electricity needs and are done in conjunction with other services such as installing the energy efficiency measures.

Energy audits are being offered at an increasing rate in the commercial and industrial sector. Despite the fact that audits are labour-intensive, costly, and do not necessarily save energy on their own, utilities are using them to pursue other objectives: (1) to gather end-use data on electricity consumption; (2) to initiate a relationship with commercial and industrial customers; and (3) to get a foot in the door so as to identify promising customers for other utility initiatives such as heat pumps, fuel-switching, and thermal energy storage (load management) programs.

One of the most successful approaches for residential retrofits has been to offer free installation of more energy-efficient equipment or devices. The idea behind *direct installation* programs is that customers often lack the time, funds, motivation, or expertise to install measures (or, alternatively, to arrange for installation) on their own This approach is frequently used for hard-to-reach markets such as low-income and rental customers who may not respond as readily to information and incentive programs.[16]

Based on the limited experience to date, it appears that where incentives are high (i.e. the customer's investment is low) comprehensive programs can achieve significant participation and energy savings. However, these programs also carry costs. In particular, the administrative burden of implementing a retrofit program can be substantial. Most programs require the use of outside contractors, relieving the utility of certain tasks but increasing the need for administrative oversight and quality control. More time is needed in program design to develop standards for installation service, contractor training, and inspection procedures.[17]

In the commercial and industrial market, rebates are a common approach and are often preceded by an energy audit. The majority of rebate programs offer fixed incentives for a prescribed list of energy-efficiency measures. Some also offer customized incentives for measures suggested by the customer. Customized rebates are usually calculated in relation to the customer's energy savings and/or contribution to reducing peak demand.

Typically, rebate programs show cumulative participation rates in the 5-10 percent range. Data on savings are limited at this time.

Utilities also have programs which are tailored to specific industrial customers because these customers have such wide divergence in their electricity needs. In certain cases, these programs use a rebate approach, with fixed incentives for standard measures (e.g. lighting and motors) and customized incentives for process changes For larger projects, utilities may issue a 'Request for Proposals' to which customers respond with their own suggested efficiency measures.

Generally speaking, most industrial programs to date have either been on a limited scale or in full-scale start-up. A review of 17 programs found typically low participation rates (less than 10 percent), but also low utility costs (under 1 cent per kWh) [18]

A summary of cumulative participation, annual energy savings, and utility cost for strategic conservation programs is presented in Table 6.1 **It is important to note that the results cover a broad range of methodologies for estimating the savings and costs of particular DSM program utilities and should therefore be viewed only as a crude indication of actual program costs.**

In North America, the key findings compiled from the past decade and a half of experience include:

(1) New construction programs can result in relatively high savings, at moderate cost to the utility. By working closely with builders, utilities have made substantial inroads into the new housing and commercial building markets.

(2) Audit and other information programs on their own have not produced significant energy savings. They are important insofar as they provide useful information on customer end-use and areas for improvement in efficiency as well as enhance the customer utility relationship. While certain kinds of programs (e.g. appliance labelling and home energy rating systems) can have a measurable impact, information programs work best when used in conjunction with other delivery approaches--for example, combined audit-retrofit programs.

Table 6.1

Summary of Strategic Conservation Programs[a]

Program Type	Cumulative Participation (%)	Annual Energy Savings (%)	Utility Cost (¢/kWh)
Residential			
New Construction	2-15 (35-80)	N/A (20-50)	2-3
Audit/Information	1-6 (15-40)	3-5 (4-8)	N/A
Retrofit			
Dir. Installation	1-7 (25-65)	2-7 (11-17)	3-7
Comprehensive	4-6 (20-85)	5-9 (10-20)	2-5
Appliance Rebate	3-12 (25-80)	N/A (4-8)	1-2
Commercial/Industrial			
New Construction	N/A	N/A (20-30)	2-3
Audit	1-4 (50-90)	4-5 (6-10)	N/A
Retrofit			
Rebate	1-4 (5-10)	N/A (7)	1-2
Perf. Contracting	0-2 (15)	N/A (15-18)	2-5
Comprehensive	1-2 (30-70)	10 (15-23)	2-4
Lighting			
Rebate	0-3 (10-25)	2-3	1-2
Dir. Installation	2-5 (25-55)	N/A (10)	1-5
Motor Rebate	0-5 (33)	4-5 (8)	1-2

[a]Results shown for "typical" programs. Bracketed ranges indicate "best" programs.

SOURCES: Barry (1991); Brown (1987); Central Maine Power (1991a); Central Maine Power (1991b); Central Maine Power (1990b); Central Maine Power (1987); Clinton and Goett (1989); Dagang (1990); Diamond, et al. (1990); Egel (1986); Hamilton (1991); Hirst (1990); Hirst, et al. (1987); Hoffman, et al. (1989); Horowitz (1991); Keating and Blachman (1987); Keating and Riewer (1989); Korda (1990); Krause, et al. (1989); Kunkle, et al. (1990); Kushler, et al. (1989); McKellar and Rosenblum (1987); Nadel (1990a); Nadel (1990b); Nadel (1989); Newcomb (1990); Okumo (1990); Quaid (1990); Quantum Consulting (1991); RCG/Hagler, Bailly (1990); Reeves (1990); Riewer and Spanner (1991); Rilling (1991); Sabo and Michelsen (1991); Sayko (1991); Schick, et al. (1991b); Schick, et al. (1990a); Schick, et al. (1990b); Schick, et al. (1990c); Spada (1991); Spellman, et al. (1987); Stout and Sanders (1990); Stucky, et al. (1990); U.S. General Accounting Office (1987); Vine and Harris (1989); Vine, et al. (1987); Warner, et al. (1991); and information from utilities.

NOTES: "Dir." stand for direct and "Perf." stands for performance.

(3) In the residential sector, direct installation programs--where the utility installs energy-efficiency measures at no charge--can lead to savings in excess of 10 percent. This approach is often used for hard-to-reach markets (e.g. low-income and rental customers), but can be comparatively expensive, especially when contractors are used and more costly retrofit measures are installed.

(4) In the commercial and industrial sectors, performance contracting is useful for utilities that prefer to hire outside contractors to implement DSM programs. Although savings in the range of 10 to 20 percent can be realized, these programs may be costly because of contractor overhead and the need for administrative oversight by the utility.

(5) Rebates for energy-efficient equipment are relatively easy to administer and constitute the lowest-cost type of program. However, these programs typically achieve only modest participation and savings, and are most effective at promoting individual efficiency measures, rather than packages of measures in which different types of equipment interact. Utilities have been moving away from rebates in recent years and towards 'user pay' programs due to increasing concern and complaints of cross-subsidization among customer groups.[19]

(6) Comprehensive (full-service) programs combining significant financial incentives, installation, and other services have the potential to reach large numbers of customers and to produce substantial savings, albeit at relatively high cost. The administrative burden of comprehensive programs can be large, often requiring the extensive use of contractors.

6.3.1.5 Lessons Learned

A number of useful lessons can be drawn from utility experience with DSM programs to date. These lessons demonstrate some of the key elements that should be considered in designing cost-effective DSM programs:

Utility commitment - Perhaps the most critical factor in achieving program success is a strong commitment on the part of utility ownership, management, and employees to DSM. This means not simply paying lip service to DSM, for example, through corporate and public relations efforts. It means building an energy-efficiency ethic directly into the corporate culture through the organizational structure, staff training, and incentives. Those which have had the most success have made DSM a top priority in their marketing departments; have provided extensive sales training to staff; and offer bonuses and awards to managers and employees for meeting targets. In addition, more aggressive jurisdictions in the United States are now offering shareholder incentives to investor-owned utilities to reward them for successful programs.

Utility staffing and expertise - Program success is also strongly linked to developing staff expertise in all aspects of DSM--program planning

and design, marketing and delivery, monitoring and evaluation. Increasingly, utilities are recognizing that they must build the internal capability to handle these functions.

Customer acceptance - Customer behaviour can be a pivotal factor in determining how a DSM program is accepted. Studies have shown that residential customers base their energy-efficiency decisions not only on the price of efficient equipment but also on considerations such as comfort, aesthetics, convenience, safety, and interest in new technologies. Commercial and industrial customers are influenced by the availability of financing, staff energy expertise, employee comfort, disruption to the work place from installing efficiency measures, and a host of other factors. As a result, programs must be designed with customer priorities in mind.

Ownership/organizational arrangements - Programs must also be tailored to fit the specific organizational and ownership characteristics of customers. For example, programs targeted at apartment buildings are usually marketed to building owners and managers because of the short tenure of renters. In the commercial and industrial sector, it may be difficult to target franchises or company branch plants where they do not have the local authority to make energy-investment decisions.[20]

Program targeting - Market research on the energy-efficiency levels of equipment, building trends, customer attitudes, etc., is crucial to designing effective DSM programs. Utilities frequently conduct focus groups and use other research methods to analyze customer behaviour. Some utilities have made special efforts to target their programs--for example, to customers with greater potential for efficiency improvement, or to industries in need of economic relief. This targeting, in turn, can lead to higher, more cost-effective electricity savings.

Capturing lost opportunities - One aspect of effective targeting is to pursue potential lost opportunities, in particular, efficiency improvements in the construction of new buildings and in the replacement of appliances and equipment. Measures of this kind typically offer a one-time chance to achieve significant energy savings, at lower cost and more conveniently than could be realized with a later retrofit.

Targeting of delivery approach - Different target markets, or different kinds of customers, may require different approaches to program delivery. Large customers react to different marketing strategies than do small customers. The owners of rental properties will have to be approached differently than individual home owners.[21]

Marketing effort - An aggressive marketing effort, targeted to the specific customer or market segment, is crucial. Most successful programs have used multiple marketing techniques including direct mail, word-of-mouth,

media advertising, toll-free hotlines, and joint advertising with trade allies. Direct personal contact between sales staff and the customer remains the most effective marketing tool, and is especially important for large commercial and industrial customers. In some cases, however, one-on-one contact may not be practical (i.e. where there are many customers to approach).

Assistance of trade allies - Another key element is the cooperation of trade allies such as equipment dealers, builders, contractors, engineers, and design professionals. These groups can either make or break a program to the extent that they frequently act as intermediaries between the utility and the customer. Effective programs have actively solicited the cooperation of trade allies and, in many cases, have used them as a primary marketing channel.

Credibility with customers - The utility or other sponsoring agency must have a high degree of credibility and trust with the customer in order for programs to succeed. In this respect, using contractors or energy service companies to deliver a program may be problematic if the customer distrusts the contractor or is dissatisfied with the final work. Utilities must be careful to use trained sales staff and qualified contractors, and must implement quality control measures to check on all aspects of program delivery from marketing through to installation and operation.

Quality control of contractors and trade allies - When the utility contracts out DSM services, utility representatives must validate the savings and the quality of the work to ensure the customer is pleased and the utility will achieve the results.[22] A recent paper identified four components[23] to ensure program success when using contractors and trade allies: (i) training and certification of the contractors and installers; (ii) motivation for proper installation through trade associations and code officials; (iii) financial incentives; and (iv) site inspections.[24]

Financial incentives - Financial incentives which cover a major share of the cost of energy-efficiency improvements appear to have some importance in ensuring customer participation. These incentives can help customers to overcome one of the principal barriers to investment--the higher initial cost of energy-efficient equipment. What the precise level of incentive should be, in order to optimize participation, is a more complicated issue.

Providing services - Evidence suggests that DSM programs are also more likely to succeed where they provide specific services to the customer such as an orientation session, design assistance, installation of measures, commissioning, and operation and maintenance services. Even with generous financial incentives, customers will often not implement efficiency measures unless the utility arranges for installation. The orientation session is essential to ensure that the customer's expectations are in line with the what the program will deliver in terms of content, timing, and responsibilities.[25] Operation and maintenance follow-up services are important not only to ensure

that equipment is functioning properly, but also to provide the utility with data on whether expected energy savings are achieved.

Comprehensive measures - Programs tend to be more successful where they attempt to package as many cost-effective energy-efficiency improvements as possible, in order to obtain the highest savings in a given application (e.g. a retrofit of an industrial plant). This represents the opposite of *cream-skimming*, where a program targets only the lowest-cost efficiency measures available.

High-efficiency technologies - Programs promoting innovative, high-efficiency technologies that have not achieved significant market acceptance can result in sizeable cost-effective electricity savings. Savings are likely to be more cost-effective because the number of free riders in the program is, by nature, lower.

Program procedures and materials - Simple application forms and other program procedures are also essential. Many utilities now package efficiency measures for a given end-use (e.g. lighting) or multiple end-uses, so that the customer is not overwhelmed with marketing materials and paperwork. Materials such as program advertising and energy analysis (audit) results should be eye-catching, personalized, and as concrete as possible. For example, experience has shown that these materials are more effective where they emphasize dollar savings and benefits such as increased comfort to the customer, where they show case-study examples of similar customers, etc..

Customer choice - Programs are more likely to succeed where they provide customers with a range of energy-efficiency options from which to choose They must be flexible in adapting to the customer's schedule, particularly in the case of large industrial firms. They must also be sensitive to customer priorities other than energy efficiency such as comfort, aesthetics, and convenience.

Minimizing risk - One of the main barriers to customer-initiated energy efficiency is the perceived uncertainty of DSM investments Some utility programs specifically address the risks of DSM by providing demonstrations of equipment, guarantees of energy savings, etc

Developing a customer relationship - More and more, utilities are becoming aware of the need to develop a favourable, long-term relationship with the customer with regard to DSM activity This is consistent with the new role of electric utilities as providers of energy services to the customer. Contrary to the argument against cream-skimming (i.e. that utilities should not go after low-cost efficiency improvements and leave other cost-effective improvements behind), it is suggested that the utility's first goal should be to get a foot in the door. The idea is that initially programs can promote easier, low-cost measures such as lighting, in order to demonstrate the benefits of

DSM to customers. Once the customer is convinced, the utility can then return with programs emphasizing higher-cost measures.

Education - Education is a key element in the long-term success of the DSM activity. The utility must educate all parties, the contractors, and the program participants of the benefits of efficient equipment and devices, the savings, and the paybacks.[26]

Consistent regulation/policy - Utilities are often reluctant to enter into the DSM field without clear and consistent regulatory and policy guidelines. For instance, regulatory authorities must establish the roles and responsibilities, cost recovery, and whether or not they will provide utilities an allowance for profit for DSM investments.[27] A very brief description of the North American initiatives are included in Table B.1 in Appendix B.

Regulatory incentives/penalties[28] - While effectiveness of regulatory incentive/penalty schemes has not yet been determined, there is a strong correlation between regions that have significant well-structured financial rewards/penalties and consequential DSM activity.[29]

Information associations/conferences - Another reason for the success of utility programs lies in the extensive information networks that have arisen Organizations like the American Council for an Energy-Efficient Economy (ACEEE), Association for DSM Professionals (ADSMP), the EPRI, Lawrence Berkeley Laboratory (LBL), the Oak Ridge National Laboratory (ORNL), the Alliance to Save Energy, and the Canadian Electrical Association, all provide quality centralized sources of information on DSM. Also important are the three major DSM conferences: the *Chicago Energy Program Evaluation Conference*, the ACEEE's *Summer Study on Energy Efficiency in Buildings*, and the National Association of Regulatory Utility Commissioner's *Integrated Resource Planning Conferences*.

Many of the elements mentioned above--utility credibility, personalized marketing, and customer choice--can contribute to a good working relationship between utilities and customers. Quality control is absolutely essential to ensure that customers are satisfied with energy-efficiency measures, that they pursue additional savings, and that they provide favourable word-of-mouth advertising for the utility.

6.3.5 The Down-side of DSM

Although little discussed in the literature, demand-side management programs do have several downsides. First, programs where the utility exchanges old worn out technologies with efficient ones present a formidable challenge to the utility regarding the disposal of the obsolete equipment. To date, utilities have dealt with this problem within the environmental guidelines set out by the respective governments. For example,

in the City of Calgary's streetlighting program, the City exchanged thousands of mercury vapour lamps with sodium vapour lamps, leaving them with the problem of disposing of the mercury vapour lamps with their 'hazardous' contents. In order to conform to provincial and municipal waste regulations, the City of Calgary had to first smash the lamps, put them in drums, and put them in sites designated for hazardous wastes.

The second issue that merits attention is the effect that electrotechnologies promoted under the guise of DSM programs have on power quality. There is growing criticism that some of these DSM electrotechnologies are causing voltage fluctuations that compromise power quality.[30] Harmonics generated by some electrotechnologies can pose problems both to the utility and to the electricity customer. On the utility system, harmonics can cause localized heating within the distribution transformer and increase T & D losses. What problems harmonics pose to the customer depends on the technology.

The two DSM technologies causing the most concern at this juncture are electronic ballasts and adjustable speed drive motors. In the case of motors, harmonics generated by adjustable speed drives can increase total motor losses by several percent; increase voltage stress on windings and their insulation; sometimes cause torque pulsation at low speeds, localized heating, and acoustic noise; excite resonant torsional vibrations; and other problems.[31]

While power quality problems have long been a concern of electric utilities, given the fervor with which these programs are being implemented, there is concern that the problem may be much larger than it has been in the past. Whether the DSM impacts on power quality serve as fodder for the opponents of DSM is not yet clear.

6.4 Review of Existing Policies and Programs Relating to Energy Efficiency in India

6.4.1 Organizations Involved in Promoting Energy Efficiency

The need for energy conservation was first recognized in the mid-1970s following the first oil price shock. In 1974, a Fuel Efficiency team was set up comprising experts from the Indian Oil Corporation (IOC), National Productivity Council (NPC) and Directorate General for Technical Development (DGTD). Recommendations of this team resulted in creation of the Petroleum Conservation Research Association (PCRA) in 1975, with major oil companies, NPC and Indian Institute for Petroleum as members.

The GOI set up an Inter-Ministerial Working Group on Energy Conservation in 1981. In 1983, the Advisory Board on Energy (ABE) was created for planning policies and programs for energy sector. In 1987, the

government created the post of Advisor Energy Conservation, reporting directly to the Cabinet Secretary, to promote activities on energy conservation with greater focus. A separate cell for energy conservation was created in the Department of Power (now Ministry) headed by a joint secretary.

The electro-technical wing in the Bureau of Indian Standards (BIS) is responsible, among others, for setting energy efficiency standards for various electricity consuming equipment. The NPC was one of the early organizations to enter the area of fuel efficiency and energy audits in the country.

MoP is today the nodal agency/organization responsible for coordinating energy efficiency activities in India. The EMC was created in 1989 as an autonomous organization under the Department of Power. EMC is the executive agency responsible for implementing and monitoring energy conservation programs. The activities of the EMC include:

- providing policy inputs to the government on energy conservation;
- promoting energy audits and providing recommendations to improve energy efficiency;
- organizing sector specific campaigns for the major energy consuming sectors; and
- conducting training programs for energy managers, supervisors, and shop floor workers.

There are also a large number of other national organizations involved in the promotion of energy conservation efforts. The Rural Electrification Corporation (REC) is involved in promoting energy efficiency of agriculture pumpsets. The energy studies centres at the Indian Institutes of Technology (IIT) are involved in carrying out research in the area of energy efficiency improvement in various end-uses. Several industry association such as the Association of Chamber of Commerce in India (ASSOCHAM), Confederation of Indian Industries (CII), and Federation of Indian Chamber of Commerce and Industry (FICCI) are undertaking initiatives to promote energy efficiency in their respective member industries. The Tata Energy Research Institute (TERI), a non-governmental organization, is also involved in promoting energy efficiency through energy audits, information dissemination, training workshops, etc.. TERI, in collaboration with Synergic Resources Corporation, a leading U.S. consulting firm in the area of energy efficiency and DSM, has set up the Asian Centre for Energy Efficiency and DSM (ASCEND) to promote DSM and energy efficiency.

6.4.2 Estimates of DSM Potential in India

One of the first official reports to examine the potential for energy efficiency in India was the report of the Inter-ministerial Working Group on

Energy Conservation (1983). The report estimated conservation potential of the order of 25 percent and 30 percent in the industrial and agriculture sectors, respectively. Several studies supported by the United Nations Development Program (UNDP) and the World Bank, place conservation potential between 20-30 percent for India (Table 6.2). This potential accounted for better housekeeping, retrofitting and minor process modification measures, and savings attributable to major technological/process change.

Table 6.2

Energy Conservation Potential in India

Sectors	Potential (percent)
Economy wide potential	Up to 20
Agriculture	Up to 30
Industry	Up to 25
Transport	Up to 20
Domestic and Commercial	Up to 20
Industries	
- Textiles	20-25
- Paper and pulp	20-25
- Ferrous foundry	15-20
- Glass	15-20
- Fertilizers	10-15
- Cement	10-15
- Chlor-alkali	10-15
- Aluminium	8-15
- Iron and Steel	8-15

SOURCE Energy Management Centre, Ministry of Power, Policy Guidelines for Energy Efficiency Promotion in Asia, (date?).

A recent study carried out by the U.S. Office of Technology Assessment shows that, based on conservative estimates for a wide range of electricity using services - cooking, water heating, lighting, refrigeration, air conditioning, electronic information services and industrial motor drives - overall electricity savings of nearly 50 percent are possible with currently available energy efficient technologies in the developing countries. Further, these technologies would provide financial savings to individual consumers over the lifetime of the equipment of more than 25 percent.

A report prepared for the World Bank and the U.S.AID, entitled Opportunities for Improving End-Use Efficiency in India examined 27 efficiency measures. For each measure, cost per kW saved and per kWh saved were examined. When the cost of a measure is lower than the cost per kW of a new power plant and/or lower than the marginal generation costs, the measure is cost effective and needs to be considered for implementation. The report concluded that ***if all the cost effective measures were to be fully***

implemented, forecasted electricity demand and peak requirements in 2004/05 for India could be reduced by approximately 20 percent.

An important point is that all these reports have estimated economic savings potential based on a given set of assumptions. The actual achievable potential or realizable potential is a subset of economic potential based largely on the participation rates of various end-users.

6.4.3 Review of Energy Efficiency Initiatives

6.4.3.1 Central Government

The Central Government has set up an Energy Conservation Cell in the MoP that formulates policy, designs energy management programs, and ensures effective coordination between different ministries and other organizations. The EMC is the executive agency responsible for implementing and monitoring energy conservation programs.

The existing programs and policies of the GOI can be broadly categorized into the following areas.

Tax incentives and duty concessions: GOI offers 100 percent depreciation in the first year on specified energy efficiency equipment and concessional excise/customs duty on notified energy conservation equipments, to promote energy efficiency.

GOI's energy audit program: The MoP, through EMC provides funds for energy audit studies in the industrial and commercial sectors. In 1989, two energy audit programs were launched by GOI jointly with the United Nations Development Program (UNDP) and the Commission of the European Communities Under these programs, energy audit buses have been deployed to undertake comprehensive energy audit studies. Regional lead agencies have been identified to carry out these audits across the country. More than 300 audits have been completed under these programs. Recently, the Ministry of Power has signed an MOU with the German technical cooperation agency, GTZ, to implement energy efficiency projects in selected industrial sectors.

Soft loan schemes for modernization and installation of energy efficient equipment: The three development financial institutions (DFIs) of India--the Industrial Development Bank of India (IDBI), the Industrial Credit and Investment Corporation of India (ICICI), and the Industrial Financial Corporation of India (IFCI)--provide financial assistance to industries which are in conformity with the national priorities as set out in the national development plans. The IDBI currently has two schemes which offer assistance for projects with energy saving devices or using renewable energy sources.

- Energy Audit Subsidy Scheme - Under this scheme, launched in June 1988, assistance is available for preliminary as well as detailed energy audits, up to 50 percent of the cost of the energy audit, limited to the lesser of Rs 1 lakhs or 0.05 percent of the gross fixed assets of the company.

- Equipment Finance for Energy Conservation Scheme - This scheme is being implemented by IDBI jointly with ICICI and IFCI. The financing under this scheme is available in the form of term loans for the acquisition of energy conservation equipment by industrial undertakings which have been in operation for at least 5 years. The interest rebate is linked to the extent the energy savings are achieved, subject to a floor level of 10 percent.

Electricity pumpsets rectification program: The SEBs, with support from the MoP and the REC, have undertaken several demonstration projects for retrofitting agriculture pumpsets. A program for rectification of 25,000 electric pumpsets was initiated in 1985/86. In 1988, another demonstration project covering 15,000 pumpsets was undertaken by the DOP in the states of Gujarat, Madhya Pradesh and Haryana. During 1989/90, 22,000 pumpsets were rectified under REC's energy conservation program. REC also provides professional guidance to farmers regarding installation of energy efficient pumping systems. The National Bank for Agriculture and Rural Development (NABARD), which is the prime lending institution for agriculture pumpsets in the country, is required to ensure that all the new pumps for which loans are raised, conform to efficiency standard specifications.

Setting efficiency standards for equipments: The Bureau of Indian Standards (BIS) is responsible for setting standards for manufacturing, operational practices and related areas in the country. A special co-ordination cell for energy conservation was set up in BIS in 1986. Out of 13,000 standards in force in the country, about 200 deal directly with aspects relating to energy efficiency Apart from standards, BIS has also laid down guidelines for selection of energy efficient equipments, guidelines for system design and proper matching of components, and codes of practice for proper equipment installation and maintenance All products which comply with standards are given BIS certification

Disclosing information on energy consumption. Under an amendment to the Companies Act, all public limited companies have to specifically disclose information on energy consumption, cost of energy, and measures to reduce energy consumption.

6.4.3.2 State Governments

Most states have entrusted energy efficiency activities to the state energy development agencies. Subsidy schemes for energy audits are also in operation at the state level through these agencies. The Gujarat Energy Development Agency (GEDA) operates an energy audit study subsidy scheme

under which 50 percent of the cost of an energy audit study (up to a maximum of Rs.20,000) is provided as a subsidy. The scheme includes both industrial plants and commercial establishments. A similar scheme is offered by Tamil Nadu Energy Agency through the Tamil Nadu Electricity Board, where energy audits conducted by approved energy consultants are subsidized to the extent of Rs.20,000 per audit.

Several state governments have granted sales tax exemptions for a number of renewable energy and energy saving devices.

6.4.3.3 Multilateral Development Banks and Bilateral Donor Agencies

Multilateral development banks and bilateral donor agencies are operating several energy efficiency programs in developing countries. Multilateral development banks have been engaged in discussions with the GOI to provide a line of credit for improving industrial energy efficiency in India. Some of the projects being supported in India by U.S.AID include the Program for the Acceleration of Commercial Energy Research (PACER); the Private Sector Energy Development (PSED) Project; and the Energy Management Consultation and Training program (EMCAT). EMCAT is a six-year, multi-million dollar program that was initiated in 1991. The EMCAT program, targeted towards private energy auditors and consultants and industrial customers or associations, provides grants for establishing energy conservation demonstration units, organizing workshops, training of energy auditors, etc..

The World Bank in their 1993 analysis,[32] concluded that continuing efforts to address country-wide policy and institutional issues are the most important means by which the largest efficiency gains can be achieved in developing countries. The Bank plans to increase its efforts to improve intermediation in the energy and information markets in developing countries in order to reduce the high cost of information dissemination and transaction and financing costs. The Bank also plans to give greater attention to the transfer of energy efficient and pollution reducing technologies in their sector activities.

6.4.4 Efficiency Gains

Though the importance of energy efficiency is well recognized and potential benefits established through various studies, the approach towards implementation of DSM activities has been rather fragmented. While, as mentioned earlier, energy conservation activities assumed importance after the first oil crisis in 1973/74, it is only in the Eighth Plan that for the first time it is recognized as a priority area with a separate budget allocation of Rs 1000 crores. The National Energy Efficiency Program (NEEP) launched during the Eighth Plan has targeted energy savings of about 5000 MW in the electricity sector, of which 2750 MW are expected to arise from end-use efficiency improvements.

Most of the energy efficiency initiatives have been in the industrial sector, particularly in energy intensive industries. Energy audits are fairly common in India but there is little evidence of efficiency gains realized following implementation of recommendations of these audits. In the agriculture sector, there have been some efforts on the part of the GOI and REC to improve the efficiency of electric pumpsets, but actual gains are almost negligible in view of the large potential for energy efficiency which remains untapped. The initiatives for energy efficiency in the domestic and commercial sectors have been limited to setting standards and provision of fiscal concessions.

Reasons for poor achievement of efficiency gains are many, which are discussed in detail in the following section. The most important reason, however, can be attributed to the lack of a comprehensive energy efficiency plan and commitment on the part of utilities to be actively involved in DSM programs. Electric utilities caught up in day-to-day operations and management problems have not accorded the desired importance to DSM. While some SEBs have set up Energy Conservation Cells in their boards, their activities have been limited to providing assistance to industries in conducting energy audits. Reasons for the low priority given to DSM by utilities include:

- there is no mandate, such as is presently provided by State Utility Commissions in the U.S., which requires the utilities to review all options on demand and supply side and develop a least cost capacity expansion plan;
- utilities are subsidized, publicly-owned monopolies and have very few incentives to improve supply efficiencies and almost no incentive to promote end-use energy efficiency;
- lack of resources specifically allocated for energy efficiency; and
- lack of adequately skilled staff to initiate energy efficiency measures and adopt DSM.

6.5 Estimating Energy Efficiency Potential in Various End-Uses

This section attempts to estimate electricity saving potential in various end-uses through end-use efficiency improvements. At the outset, it is important to distinguish between what is technical potential versus what is economically feasible Technical potential is defined as the hypothetical maximum that may be achieved if all end-use devices were to be replaced by the latest and most energy efficient counterpart, regardless of the relative costs, commercial availability, customer awareness, etc.. The technical potential assumes a 100 percent participation rate and therefore represents an upper bound for the potential savings from energy efficient technologies.

The economic potential is defined as the maximum possible reduction in electricity demand under a specified set of economic assumptions. These assumptions primarily include capital and operating costs of the measure, cost of electricity to the end-user, and discount rates assumed by end-users. Economic potential estimates are essential to decide on the cost effectiveness of different DSM measures and thus enable a prioritization of these measures for implementation.

The realizable potential is a subset of economic potential taking into account participation rates based on factors such as ease of availability, convenience of use, consumer acceptance, etc..

The analysis in this section is based on estimates of realizable potential for energy efficiency in various end-uses. The approach followed comprises the following steps.

- Analyze and estimate sectoral electricity use pattern
- Disaggregate sectoral demand by major end-uses
- Forecast sectoral electricity consumption until the year 2011
- Identify major energy-efficiency improvement options for each end-use and sector
- Estimate the cost-effectiveness of various energy efficiency options
- Estimate realizable potential of electricity savings in each sector.

6.5.1 Sectoral Electricity Demand Analysis

Electricity consumption in India has grown at a compound annual rate of 10 percent during the period 1950 to 1991/92 (Figure 6.1). The pattern of consumption has undergone a significant change during the past four decades, with the largest increase seen in agriculture and domestic sales as a percent of total electricity consumption. The consumption pattern also varies across regions.

The industrial sector accounts for the largest share of total electricity consumption. However, its share has declined from 70.6 percent in 1965/66 to 42 percent in 1991/92. This decline may be attributed partly to the high growth rate of electricity consumption in other sectors, particularly agriculture and the domestic sector. Also, a large number of industries are increasingly relying on their own generated captive power because of rising shortages of utility power and poor quality of the power supply. In 1991/92, a survey of 1427 industries showed that on-site generation accounted for nearly 47 percent of their total electricity demand. Among the five regions, the share

of electricity consumption in the industrial sector is highest in the Eastern region (55 percent) and lowest in the Northern region (33 percent).

The rural electrification program launched by the GOI in the mid-1960s resulted in a large-scale adoption of electric pumpsets. Compounded by subsidized electricity tariffs and the fact that in most of the states electricity supply to the agriculture sector is not metered but is based on the horsepower of the pumpsets, this has led to a rapid increase in electricity consumption in the agriculture sector. Consequently, the share held by the agriculture sector has increased from a mere 7 percent in 1965/66 to 28 percent in 1991/92. In some states like Punjab, Harayana, Uttar Pradesh, and Andhra Pradesh nearly 35-40 percent of total electricity consumption is for irrigation purposes.

Electricity consumption in the domestic sector increased at a compound growth rate of about 11 percent per annum during the last four decades, resulting in an almost doubling of its share in total electricity consumption. Increased urbanization and increased use of domestic electrical appliances are two important reasons for this growth.

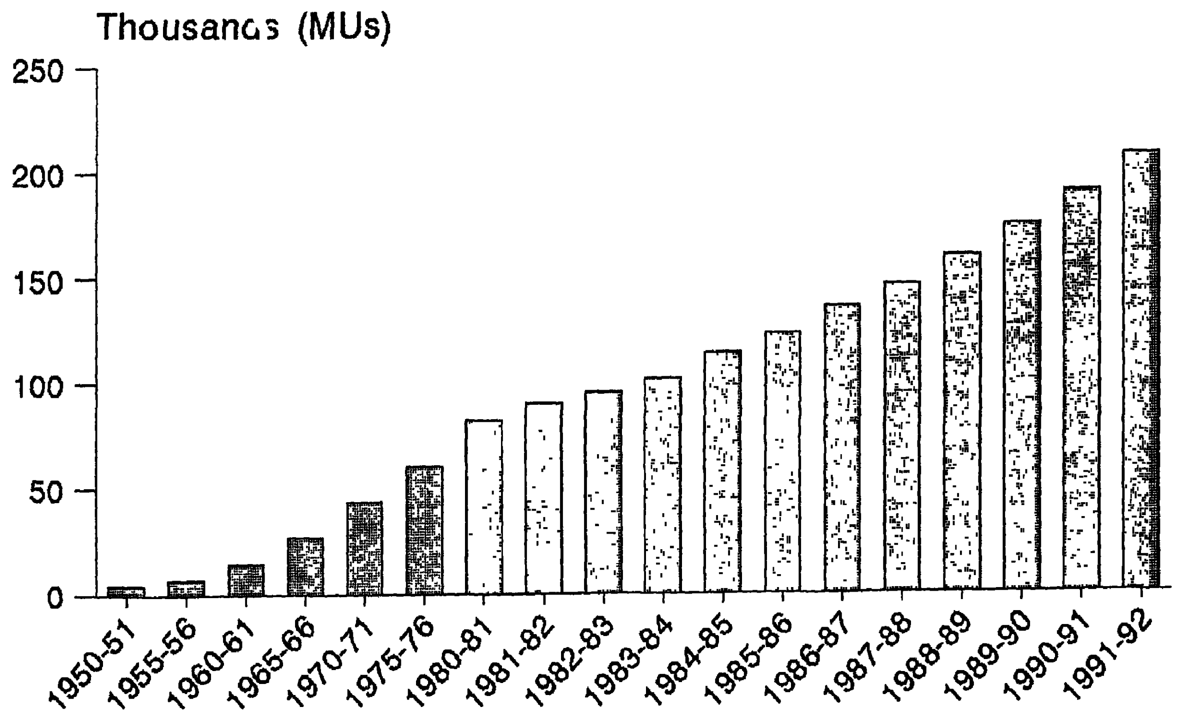
The commercial sector, comprising shops, offices, institutions, hotels etc., continues to account for 5-6 percent of total electricity sales. Today, electricity is also finding greater use in the transport sector, largely in railways which account for 3.2 percent of total consumption. Sectoral electricity consumption during 1970/71 and 1991/92 are compared in Figure 6.2.

6.5.2 Electricity Demand Projections Until 2011

Electricity demand projections for the country are carried out periodically by the Electric Power Survey Committee (EPS) set up by the Government of India. Sectoral demand projections through the EPS are made available for a period of five years. Beyond this five year period, total annual requirements at the national level are estimated, based on extrapolation. The CEA has for the first time carried out a detailed exercise to forecast sectoral electricity consumption for the period 1990/91 to 2006/07. Unlike other forecasts of the GOI, which are based on trend analysis and end-use methods, the CEA forecasts have been estimated using econometric modelling techniques.

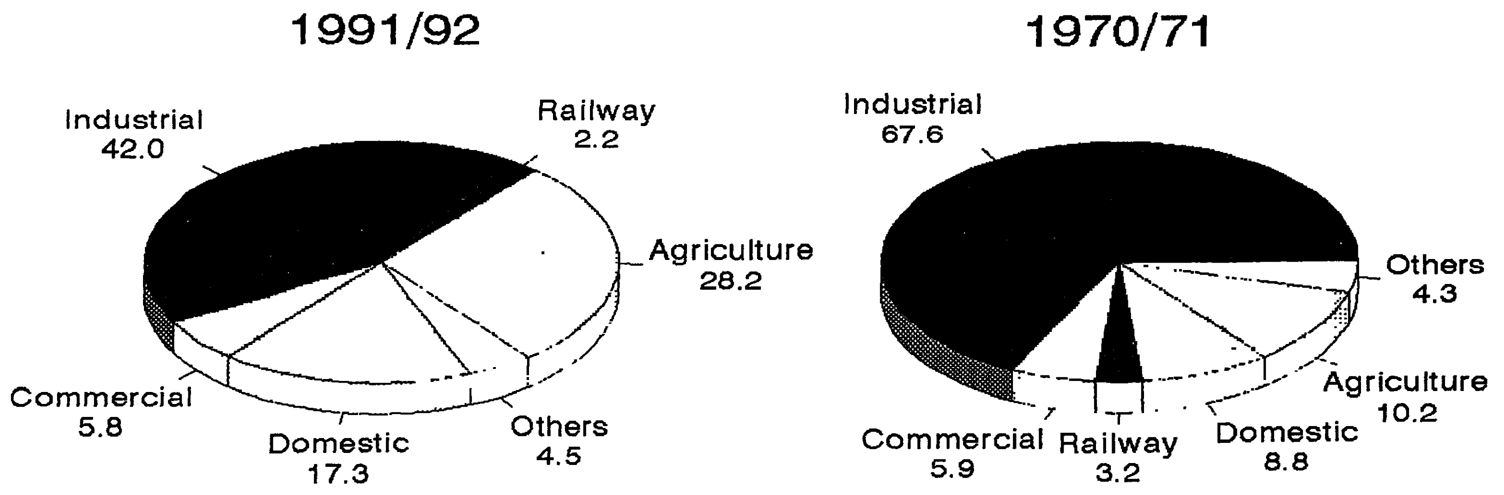
Sectoral demand projections estimated by the CEA are considered as the baseline for estimating electricity savings potential. The CEA's forecast to 2006/07 is further extended to the year 2011 based on trend analysis. Demand for electricity is estimated to grow at a compounded annual rate of 8.3 percent during the period 1992/93 to 2011/12. Among the various consumer categories, demand is estimated to grow at an annual rate of 12.8 percent in the domestic sector and 9.8 percent in the commercial sector.

Figure 6.1
Trend in Electricity Sales



SOURCE: General Review, Public Electricity Supply--All India Statistics, Central Electricity Authority, GOI, various issues.

Figure 6.2
Sectoral Electricity Consumption



SOURCE: General Review, Public Electricity Supply--All India Statistics, Central Electricity Authority, GOI, Various issues.

Industrial electricity demand is estimated to increase at a rate of 6.7 percent during this period, while growth in electricity demand for the agriculture sector is forecast to decline significantly after 2001/02. Consequently, the sectoral composition of electricity consumption in the 2001-2012 period is estimated to change significantly with the domestic sector accounting for the highest share. Details of regional sectoral demand projections for the period 1992/93 to 2011/12 are given in Table 6.3.

6.5.3 Electricity Demand by End-use

Information on electricity demand by various end-uses is limited and is based on a few sample surveys carried out in different parts of the country. The analysis for demand by various end-uses is based on the recent work undertaken for the U.S.AID study on Opportunities for Improving End-use Efficiency in India, 1991.

In 1991/92, the domestic sector consumed 17 percent of the total electricity sales in the country. Both the number of consumers and per capita consumption of electricity in the domestic sector are growing at a fast rate, and the share of the domestic sector in total electricity consumption is estimated to increase to 36.6 percent by 2006/07. Important end-uses in the domestic sector include lighting, fans, refrigeration, air-conditioning, use of desert coolers, and several other electrical appliances such as TVs, electric irons, geysers, etc.. Several reports have estimated that fans account for the largest share, nearly one-third of domestic electricity consumption, followed by lighting accounting for a 28 percent share. Refrigerators account for about 12.5 percent of total electricity consumed in this sector and the share of air-conditioning is estimated at 7 percent.

The commercial sector comprises shops, hotels, office buildings and institutional buildings. The major end-uses in the commercial sector are lighting, accounting for nearly 50 percent of total electricity consumption, and air-conditioning and ventilation (HVAC), comprising a 40 percent share. A breakdown of electric use in hotels indicates that HVAC systems account for 50 percent of the connected load, lighting accounts for 20 percent and water heating, cooking, and water treatment account for the balance. A survey of a large government office in New Delhi conducted in 1989 estimated that lighting is the largest end-use, consuming 33 percent, followed by equipment and elevators consuming 22 percent, air conditioning--17 percent, heating--16 percent, and fans and coolers--12 percent of the total electricity used in the building (TERI 1989).

In the industrial sector, electric motors are the single most important end-use accounting for nearly 75 percent of total electricity consumption; lighting accounts for nine percent of electricity use. In the agriculture sector, nearly all the electricity is used by irrigation pumps.

Table 6.3

Sectoral Electricity Demand under BAU Scenario

	Agriculture	Domestic	Commercial	Industry	Railways	Others	Total
92/93	53 315	44 451	12 968	100 225	4 796	9 968	225 723
93/94	56 651	51 690	14 623	107 752	5 121	11 235	247 072
94/95	60 256	59 981	16 467	115 809	5 467	12 627	270 607
95/96	64 028	69 444	18 529	124 401	5 833	14 168	296 403
96/97	68 091	80 208	20 839	133 531	6 219	15 876	324 764
97/98	72 400	92 621	23 436	143 203	6 623	17 776	356 059
1998/99	77 027	106 223	26 364	153 422	7 048	19 896	389 980
1999/2000	81 926	121 802	29 675	164 191	7 493	22 274	427 361
2000/01	87 235	139 339	33 420	175 517	7 957	24 946	468 414
2001/02	92 850	159 041	37 701	187 403	8 442	27 967	513 404
2002/03	93 507	176 722	40 338	199 854	8 947	29 820	549 188
2003/04	94 260	195 919	43 180	212 877	9 470	31 845	587 551
2004/05	95 125	216 729	46 245	226 477	10 015	33 947	628 538
2005/06	96 118	239 252	49 554	240 660	10 578	36 249	672 411
2006/07	97 258	263 599	53 129	255 431	11 161	38 726	719 304
2007/08	98 219	291 318	57 014	271 590	11 807	41 424	771 373
2008/09	99 190	321 957	61 229	288 771	12 496	44 347	827 989
2009/10	100 170	355 823	65 804	307 039	13 229	47 515	889 580
2010/11	101 159	393 255	70 774	326 463	14 011	50 953	956 616
2011/12	102 159	434 630	76 178	347 116	14 844	54 687	1 029 614

SOURCE: Central Electricity Authority.

Aggregated across all sectors, industrial motors have the largest share in total electricity consumption (38 percent). Agriculture pumps account for 23 percent of electricity use, followed by lighting--14 percent, domestic appliances--11 percent, and other industrial end-uses--9 percent (see Figure 6.3).

6.5.4 Options for Improving Energy Efficiency

6.5.4.1 Domestic Sector

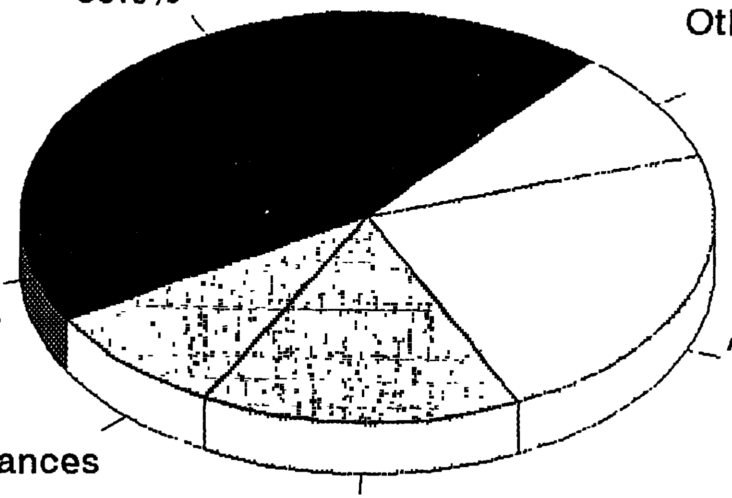
There is significant technical potential for energy conservation in the domestic sector through use of the following options:

- efficient lighting systems including high efficiency fluorescent lamps, compact fluorescent lamps (CFLs), electronic ballasts and sensors;
- high efficiency fans and electronic speed controls;
- moderate and high efficiency refrigerators;
- high efficiency air conditioners; and
- improving efficiency of evaporative coolers.

Efficient lighting systems: Present lighting use in the domestic sector is largely from incandescent lamps (7.4 TWh) and to some extent from tubelights (0.3 TWh). Over 80 percent of incandescent lighting energy use is in the domestic sector while only 10 percent of the tubelights are used by this sector. In the domestic sector, there exists a very strong case for substituting low efficiency incandescent with high efficiency fluorescent, while maintaining or increasing the level of lumen output. The following three options are considered for increasing the efficiency of lighting system in domestic sector:

- replace incandescent (commonly referred to as GLS, general lighting service) with fluorescent tube lights (FTLs). A typical 60 watt GLS can be replaced with a 20 watt FTL (plus 14 watt for ballast) thereby saving 43 percent of electricity use, while providing about 50 percent more light output;
- replace GLS with compact fluorescent lamps (CFL). Substituting a 60 Watt GLS by an 11 Watt CFL (plus 5 Watt for ballast) reduces electricity use by 73 percent, while increasing the light output marginally; and
- use of thin diameter fluorescent (called 'slimlines'). These consume 10 percent less energy compared to FTLs for the same levels of light intensity. Also, there is no difference in the costs of 'slimlines' and FTLs.

Figure 6.3
End-Use Electricity Demand
1991/92



SOURCE: Steven Nadal, V. Kothain, and S. Gopimath, Opportunities for Improving End-Use Efficiencies in India. Prepared for the World Bank, USAID, November 1991.

Fans: Fans account for about one-third of electricity consumed by the domestic sector. Field tests indicate that most fans in operation have a higher wattage than that specified by BIS.[33] Two energy-saving options available for fans are use of energy efficient-motors and electronic regulators. Motor efficiency can be increased by 10 percent at 30 percent higher costs.[34] At low speeds, use of electronic fan-speed regulators can reduce electricity consumption by 10-20 percent compared to conventional regulators. Fans with energy efficient motors are presently not available in India, but the technical capability of manufacturing them does exist. Therefore, it is assumed that in the future, new fans will be equipped with energy efficient motors.

Refrigerators: Refrigerators account for about 16 percent of the total electricity used by the domestic sector. Efficiency of refrigerators used in India is very low. A typical 165 liter Indian refrigerator consumes 540 kWh per year, compared to a Brazilian model of 225 liter consuming 410 kWh and a new Korean 200 liter model consuming 240 kWh per year.[35] In addition to poor efficiency, Indian refrigerators also have low power factors of 0.5-0.7, resulting in excessive distribution losses.[36]

Efficiency of refrigerators can be increased moderately through use of foam insulation, increased thickness of insulation, use of high efficiency compressors, increased evaporator surface, and use of tighter door seals. All these measures are estimated to reduce average electricity consumption by refrigerators to 410 kWh per year. Refrigerator models incorporating some of these measures are already available in Indian markets, and their market share is expected to increase in the coming years. Further efficiency improvements in refrigerators are feasible through technical improvements. High efficiency, CFC free refrigerators are in an advanced stage of development. Electricity consumption by these refrigerators (165 liters) is estimated to be in the order of 300 kWh per year--savings of more than 44 percent compared to conventional models in use.[37] It is expected that high efficiency CFC free refrigerators will be available in the Indian markets by 2001/02.

Air-conditioners: Room air-conditioning accounts for a very small share in total electricity consumption by the domestic sector, but often represents the heaviest load for individual households using ACs. Therefore, even a modest improvement in efficiency can result in substantial savings for individual consumers. Also, with rising income levels, demand for ACs is rising and thus their efficiency improvement has a significant impact on future demand.

The energy efficiency of an AC is measured in terms of energy efficiency ratio (EER), defined as BTU of cooling output divided by the amount of power input. The ACs available in India normally have an EER ranging between 7 to 8. Air-conditioners with higher efficiency (EER of 9) are also available but at higher costs.

Evaporative coolers: Evaporative coolers, commonly referred to as desert coolers, are generally used in those parts of India where humidity levels are less than 50 percent during summer months. Most of these coolers are assembled in small-scale manufacturing units and efficiencies are invariably low. A study carried out by the EMC reveals that a typical evaporative cooler uses 20 percent more electricity compared to the standards laid down by the BIS. Energy efficiency of evaporative coolers can be improved through use of standardized fan and pumps and proper designing of fans and pump-sets. Efficiency improvements up to 20 percent can be achieved through these measures.

6.5.4.2 Commercial Sector

Major end-uses in the commercial sector are lighting and HVAC systems. Fluorescent lamps in the commercial sector consumed an estimated 6.2 TWh, while incandescent and other consumed 1.4 TWh. The energy efficiency options considered for lighting systems are:

- replace GLS with FTLs;
- replace GLS with CFL;
- complete switch over to 'slimlines'; and
- replace HPMV with HPSV lamps. In most applications HPMV lamps can be substituted by HPSV lamps, resulting in an energy savings of 40 percent, while possibly getting more lumen output. A 150 watt HPSV can replace a 250 watt HPMV lamp.

Large commercial establishments, office complexes and large hotels are increasingly moving to central air-conditioning on their premises. In most parts of India, central air-conditioning is in use almost throughout the year. Efficiency of the HVAC system can be increased through reduced heat gain into the building, improved efficiency of equipment, improved controls and use of more efficient distribution systems. A study carried out for New York State found that commercial building HVAC energy use could be reduced by about 50 percent. Another study for Brazil has estimated 40 percent savings in HVAC systems for 2010.[38]

Proper preventive maintenance to control leakages, effective use of sophisticated thermostat, and other control systems allow the user to reduce energy consumption for air-conditioning systems. Other options that can be considered include optimization of chiller systems, use of cheap off peak power (if available) to chill water required for air-conditioning, and using the chilled water throughout the day for space conditioning. In hotels, restaurants, hospitals, etc., where waste heat is available, use of vapor absorption refrigeration can significantly reduce electricity demand.

Electricity savings of 20 percent are assumed with the use of efficient HVAC systems. VAR is not considered in estimating savings potential for the commercial sector because of very high initial costs (50 to 70 percent higher than conventional system costs).

6.5.4.3 Agriculture

The number of pumpsets energized during the last ten years has increased at a compound annual rate of 15.7 percent. There are 9.6 million pumpsets energized in the country as of March 31, 1993. Several surveys carried out to measure the efficiency of pumpsets have revealed poor operating efficiencies of both electric and diesel pumpsets. Surveys carried out by the Institute of Co-operative Management in Gujarat with support from NABARD, PCRA, GEB and REC, indicate that nearly 90 percent of the agriculture pumpsets installed are faulty and consume 150-200 percent more electricity than that required for properly selected pumpsets. Retrofitting of 300 pumpsets carried out under this study resulted in a reduction in total connected load from 4129 HP to 2125 HP, for savings of 48 percent [39] Savings achieved in several demonstration projects range between 16 to 55 percent. Reasons for high electricity consumption in agriculture pumpsets include:

- improper selection of pumpset size. A study conducted in the state of Gujarat revealed that 50 percent of the pumpsets had ratings that were 50-75 percent higher than the required rating, resulting in underloading of the pumpsets;
- improper selection of foot-valves, undersized delivery pipes, improper pipe fittings etc., causing high frictional losses; and
- use of pumps with low efficiency.

These to a large extent can be attributed to lack of information and knowledge on the part of farmers, lack of standardization, and ineffective monitoring and control on the part of the financial institutions. Also, electricity supply to the agriculture sector in India is largely unmetered. Agricultural consumers are charged for electricity based on the capacity of the pumpset installed (HP of pumpset) rather than the hours of usage of the pumpset. Such a system provides no incentive to limit the hours of operation nor to improve pump efficiency.

Two options are considered for electricity savings in the agriculture sector.

<u>Retrofitting of existing pumpsets</u>: Retrofit measures can be categorized under four levels:

- R1 - Replacement of high friction suction pipes and foot-valves by low friction suction pipes and foot-valves;
- R2 - R1 plus similar change in delivery pipes;

- R3 - R2 plus replacement of inefficient pumps by efficient pumps; and

- R4 - Complete replacement of the existing pump, motor, piping system etc., by new, more efficient systems.

Several demonstration projects carried out to retrofit agriculture pumpsets have reported 18-27 percent savings through use of options R1 and R2. Option R3 is estimated to provide 30 percent savings and as high as 50 percent savings can be achieved through use of option R4.[40]

Use of new high efficiency pumpsets: High efficiency pumpsets consume 20 percent less electricity compared to the typical pumping system used at present by agriculture consumers. The additional cost of a high efficiency pumping system is modest (Rs 2500) for a typical 4 kW system. It is expected that all new pumpsets will be energy efficient.

6.5.4.4 Industry

Energy intensity of Indian industries is quite high compared to that in developed and several developing countries. In the industrial sector, several studies have been carried out and numerous energy audits conducted to illustrate the potential for energy savings. A survey carried out by the NPC and the Petroleum Conservation Research Association estimated an energy savings of the order of 15-20 percent through proved operation and maintenance practices. Another 10-15 percent savings could be achieved by investing in more efficient technologies. Energy audits carried out for 45 industries in six energy intensive sub-sectors of industry under a GOI-UNDP program, estimated savings potential of 15 percent (MoP, 1993).

The energy intensive industries are iron and steel, chloro-alkali, aluminium, cement, textiles, paper, petrochemicals, and fertilizers. In 1991/92, these industries accounted for 75 percent of total electricity consumption (utility and non-utility) by industries with captive plant of 1 MW and above. With the liberalization of the Indian economy, energy intensive industries will be driven by market forces to adopt energy efficiency measures in order to be more competitive. Also, industries under administrative price control such as paper aluminium, and steel have been decontrolled and the inertia due to cost-plus-pricing has been overcome, leading to major investments being made for energy efficiency improvement in these industries.

Investment trends indicate that the specific energy consumption of several energy intensive industries is on the decline. For instance, the specific energy consumption of the Steel Authority of India (SAIL) was reduced from 10.14 Gcal per ton of crude steel in 1988/89 to 9.77 Gcal in 1989/90. The weighted average specific power consumption in the cement industry was reduced by 8.25 percent in 1991/92 compared to 1990/91. Aluminum production is a very energy intensive process, accounting for eight percent of

total electricity consumed in the industrial sector in 1989/90. Energy consumption in Indian aluminum plants ranges from 14,000-18,000 kWh per tonne. As against this, NALCO, the most efficient plant in the country uses only 12,800 kWh per tonne. Most of the aluminium plants in the country have plans to improve their electricity consumption to around 15,000-16,000 kWh/tonne. Similarly, in the chloro-alkali industry (accounting for 3 percent share in total electricity consumption), while most plants presently use the mercury process, future plants will adopt the membrane process which will result in savings of 800 kWh/ton of chlorine and related products produced. This process also reduces environmental and health concerns, improves product quality, reduces chemical consumption, and improves plant operations.

The CEA, in carrying out demand forecasts for electrical energy requirements for the industrial sector, does take into account future plans of expansion, renovation and modernization, and technology upgrading in electricity intensive industries. Therefore, electricity savings resulting from efficiency improvement measures planned by these energy intensive industries and the fact that new units will use energy efficient technologies, are already built into the demand projections of the CEA.

Energy efficiency options considered for estimating savings potential in the industrial sector in this report primarily include efficiency gains through motor rewinding, use of high efficiency motors, proper sizing of pumps, savings in lighting, and adoption of electric arc furnaces. The savings potential estimated thus reflects gains in existing consumption through these measures.

Motor loads account for about 80 percent of the total load in the industry. Energy efficient motors, being more expensive, have not made major inroads into the Indian industry. Due to frequent fluctuations in voltage, there are frequent motor burnouts and industries resort to rewinding. It is important in rewinding motors that adequate care is taken to ensure quality and provide proper insulation, in order to achieve increased energy efficiency. NPC estimates that motor energy use can be reduced by 2-3 percent from improved repair and rewinding practices. Field surveys conducted by TERI estimate a seven percent savings in electricity use for a typical 20 hp motor, through proper rewinding, motor sizing and improved operations. Electricity savings of 2-5 percent can be achieved through use of high efficiency motors.

Pumping accounts for about 20 percent of industrial motor energy use. Electricity savings of the order of 15-20 percent are achievable through use of high efficiency pumps (these pumps cost almost the same as less efficient pumps) and minimizing frictional losses in the pipes (NPC 1991). Derating or replacing oversized pumps can yield 5-10 percent electricity savings (NPC 1991).

Electric arc furnaces, accounting for 3 percent of electricity use in the industrial sector, consume 600 to 900 kWh per tonne of steel output. There are several measures that are available for improving the efficiency of electric arc furnaces, such as using better power factor controls, computerized control and automation, scrap pre-heating, etc.. It is estimated that if all these measures are implemented, electricity savings would be as high as 50 percent. However, not all measures are suitable for all electric arc furnaces and, therefore, an average saving of 30 percent is perhaps more realistic.

6 5 5 Cost Effectiveness of Energy Efficiency Measures

Of the technological options available for end-use efficiency improvement for various end-uses, consumers will primarily consider those options which are cost effective. The three most commonly used approaches to estimating the cost effectiveness of an energy efficient measure are simple payback period, cost of energy saved, and cost of peak generating capacity saved. While the first two give the cost-effectiveness from the consumers' point of view, the third criteria is primarily to assist the utility to take a decision.

6.5.5.1 Simple Payback Period

Cost effectiveness of a technology can be measured in terms of simple payback period (SPP) defined as the ratio of total cost of the energy efficient technology and the benefit to the consumer as a result of adopting that technology The lower is the payback for the option, the more attractive is the option. SPP is a simple index which helps the consumer to evaluate the cost-effectiveness of an energy efficient option. However, there are two basic drawbacks of this measure. First, it does not consider the useful life of the option; a two year payback may be good for a project which lasts for 15 years but may not be attractive enough for a project which lasts only three years. Second, SPP does not consider the time value of money; the initial investment is compared with savings in a particular year, rather than the discounted benefit over the life of the option. As a result, it tends to understate the true net benefits of technology adoption.

6 5.5.2 Cost of Saved Energy (CSE)

CSE is the levelized cost of the energy efficiency measure per kW.h saved and is calculated as:

$$CSE = \frac{MC * CRF}{\text{Annual kWh saved}}$$

where,

CSE = Cost of saved energy (Rs/kWh)
MC = Measured cost (Rs)
CRF = Capital recovery factor

The CSE of a measure can be compared to the marginal cost of electricity generation and supply to the consumers to estimate the cost effectiveness of the measure. The lower the CSE of a measure compared to the marginal cost of generation and supply, the more cost effective is the efficiency improvement measure.

6.5.5.3 Cost of Measure Per kW of Peak Generating Capacity Saved

This is calculated as:

$$CPGCS = \frac{MC}{kW\ savings * PCF * [1-TDLF]/CUF}$$

where,

CPGCS = Cost of peak generating capacity saved (Rs/kW)
MC = Measured cost (Rs/kW)
PCF = Peak coincidence factor
TDLF = Transmission and distribution loss factor
CUF = Capacity utilization factor

These costs are estimated for a stipulated long term period, say 20 years. For measures with a shorter life, equipment replacement costs are discounted and incorporated in the calculations. Peak coincidence factor is the proportion of equipment operating during system peak hours. T & D losses are assumed at 23 percent and the capacity utilization factor is taken to be 60 percent.

The energy efficiency measures which have a cost per kW of peak generating capacity saved which is less than the cost per kW of new generating plant, must be evaluated by the utilities as a viable option in order to minimize costs of meeting their new demand. The basic limitation of this parameter is that it does not include any credit for fuel and operating costs saved due to reduced demand from the energy efficiency measure.

For all the measures identified above for efficiency improvements, estimates of simple pay back period, cost of measure per kW of generating capacity saved, and cost of saved energy are provided in Table 6.4. It is evident that most of the options considered have a simple pay back period varying between 0.5 to 3 years. All the measures considered are cost effective when compared to a capacity cost of Rs 30,000/kW for new coal-based

thermal power plants. Also, in terms of the cost of saved electricity all the options are less that Rs 1.06/kWh, which is significantly lower than the long run marginal cost of generation and supply of electricity of Rs 1.73 to Rs 2.02 (1990/91 price level) estimated by the World Bank.

It is evident from Table 6.3 that in the industrial sector, rewinding and sizing of motors, and savings in arc furnaces are the most cost effective measures. In the domestic and commercial sectors, energy efficient lighting systems are the attractive options and in the agriculture sector, retrofitting of pumpsets has the most significant potential for electricity savings.

6.5.6 Electricity Savings Potential

Electricity savings potential in various consuming sectors is estimated based on realistic participation rates as a result of favorable economics of the energy efficient technologies, discount rates assumed by the consumers, availability of energy efficient technologies, etc..

The sectoral demand estimates of the CEA are considered as the BAU scenario. The demand for electricity in each consuming sector is disaggregated into end-uses. As mentioned earlier, since there is no time series data on the share of different uses in sectoral demand, the first option is to assume that the share of various end-uses in sectoral demand remains unchanged during the period under consideration. This was followed by carrying out sensitivity analysis for different shares of various end-uses in sectoral electricity demand. The analysis reveals that the impact on the estimate of realizable savings potential is marginal. For instance, in the commercial sector, when the share of incandescent lighting is reduced from 9.3 percent to 7.5 percent, share of fluorescent lighting is increased from 49.1 percent to 50.5 percent, and share of HVAC is increased from 32 percent to 34 percent, in the year 2001/02, the overall savings from the commercial sector is estimated to increase marginally from 10.8 percent to 11 percent in 2011/12.

End-use demand estimates are translated into appliances based on average capacity of the appliance, average hours of usage, and average efficiency rate of usage of the appliance. Using conservative market penetration rates of energy efficiency options, and average efficiency gains from adopting these options, electricity demand is estimated. For instance in the agriculture sector, it is assumed that: (i) one percent of the existing electric agriculture pumpsets will be retrofitted every year resulting in 25 percent savings in electricity consumption; and (ii) all new pumpsets installed in the future will be energy efficient pumpsets providing 20 percent efficiency gain. Estimates of savings potential in this sector is highly sensitive to market penetration rates. For instance, savings increase from 14.2 percent to 18.2 percent in 2011/12, if the number of pumpsets retrofitted every year is increased from one percent to two percent of total pumpsets in use.

Table 6.4

Cost Effectiveness of Various Measures for End-use Efficiency Improvement

Energy Efficiency Measure	Simple Payback	Cost of Measure/kW Saved (Rs/kW)	Cost of Saved Electricity (Rs/kWh)
A. Domestic Sector			
Replace GLS by CFL	2.12	9 198	0.99
Replace GLS by FTL	3.65	3 360	0.36
Replace FTL by TLD	0.00	0	0.00
Moderate Efficiency Refrigerators	11.20	20 739	0.93
High Efficiency Refrigerators	13.57	25 136	1.12
Energy Efficient Fans	6.52	7 378	0.54
Energy Efficient ACs	3.32	5 016	0.31
B. Commercial Sector			
Replace GLS by CFL	1.06	10 278	0.74
Replace GLS by FTL	0.79	2 577	0.18
Replace FTL by TDL	0.00	0.00	0.00
Replace HPMV with HPSV	0.35	-4 248	- 0.18
New HVAC System	1.82	11 110	0.48
C. Agriculture Sector			
Retrofitting of Pumpsets	1.64	5 076	0.12
Energy Efficient Pumpsets	3.56	11 036	0.25
D. Industrial Sector			
Rewinding, Sizing of Motors	0.55	10 231	0.38
High Efficiency Motors	1.80	15 385	0.57
Optimizing Industrial Pumps	2.43	21 259	0.79
Savings in Arc Furnaces	0.80	9 385	0.35

SOURCE: Tata Energy Research Institute.

In the commercial sector, an increase in the market penetration rate for the CFL lighting option from five to 7.5 percent in 2001/02 onwards, results in savings increasing marginally from 10.8 percent to 11.09 percent in 2011/12. In the industrial sector, the combined effect of increases in the market penetration rates for high efficiency motors (10 percent to 15 percent), electric arc furnaces (50 percent to 75 percent for retrofitting of existing furnaces), and for new industrial pumps (60 percent to 75 percent) is to increase savings from 5.44 percent to 5.64 percent in 2011/12.

Details of the assumptions used to estimate electricity savings potential in various end-uses is provided in Annex 1.

It is estimated that the Indian power sector can save 6.29 percent of the total electricity demand by 1996/97 and up to 8.21 percent in 2011/12, through adoption at energy efficiency and DSM options. Maximum benefits are estimated to come from the agriculture, residential and commercial sectors. Demand for electricity under the BAU scenario and energy efficiency (EE) scenario are compared in Table 6.5. Regional electricity demand under BAU scenario and EE scenario are provided in Table 6.6.

6.6 Barriers for Energy Efficiency and DSM in India

There is little doubt that India's electric power sector could gain from the implementation of energy efficiency and DSM programs. Technical potential and cost effectiveness of various measures for improving end-use efficiency are well established. However, actual efficiency gains remain far from being realized, due to a variety of technical, policy, institutional, financial and information related barriers. This is further constrained by the fact that often the costs and benefits of increased efficiency are shared by several parties. An understanding of barriers to economic investment in efficiency is crucial to a successful DSM strategy.

Some of the important barriers identified for promoting energy efficiency in India and possible options to overcome these barriers are discussed in this section. A distinction is made between barriers for energy efficiency and DSM.

Table 6.5

Sector-wise Demand for Electricity Under BAU and EE Scenarios

	Domestic	Commercial	Agriculture	Industry	Total
1996/97					
BAU	80 208	20 839	68 090	133 530	324 762
DSM	74 333	19 716	63 895	124 300	304 339
% savings	7.32	5.36	6.16	6.91	6.29
2001/02					
BAU	159 041	37 702	92 850	187 404	513 406
DSM	144 696	35 443	83 117	175 705	475 370
% savings	9.02	5.99	10.48	6.24	7.41
2006/07					
BAU	263 599	53 128	97 259	255 431	719 304
DSM	238 006	49 288	86 087	240 649	663 916
% savings	9.71	7.23	11.49	5.79	7.70
2011/12					
BAU	434 630	76 178	102 160	347 116	1 029 614
DSM	389 873	67 939	89 479	328 218	945 102
% savings	10.30	10.81	12.41	5.44	8.21

SOURCE: Tata Energy Research Institute.

Table 6.6

Regional Demand for Electricity Under BAU and EE Scenarios

	Northern Region	Western Region	Southern Region	Eastern Region	North-eastern Region
1996/97					
BAU	94 180	111 257	76 354	37 631	5 340
DSM	88 192	104 094	71 384	35 371	5 058
% savings	6.36	6.44	6.51	6.01	5.28
2001/02					
BAU	146 138	179 734	113 684	61 047	12 849
DSM	134 296	166 927	105 042	56 834	120 91
% savings	8.10	7.13	7.56	6.90	5.90
2006/07					
BAU	197 357	261 531	156 799	83 229	20 387
DSM	180 516	242 515	144 590	77 439	19 172
% savings	8.53	7.27	7.79	6.96	5.96
2011/12					
BAU	279 207	378 266	221 602	117 081	33 530
DSM	253 944	348 851	203 442	108 747	31 213
% savings	9.05	7.78	8.20	7.12	6.91

SOURCE: Tata Energy Research Institute.

6.6.1 Energy Efficiency

High cost of energy efficient equipment: The cost of energy efficient equipment is invariably higher than standard equipment normally purchased and the end-user's decision is largely based on the initial capital outlay. Consumers often seek to minimize the initial cost of equipment even though this may result in higher operating costs. This also applies to energy efficient equipment procured from outside the country. It is here that the manufactures have an important role to play in developing the market for such equipment. Further, government policies on taxes and duties can help in bringing down the cost of energy efficient equipment. There is a need to identify innovative financing options to reduce the initial cost of energy efficient equipment and also to share the risk of trying out new technologies.

Limited availability of energy efficient technologies: Most energy efficient equipment is not widely available in India. Domestic manufacturers are reluctant to invest in producing energy efficient equipment because of perceived limited demand. The domestic manufacturer of energy efficient equipment is also constrained by limited availability of raw materials and components, and taxes and duties on imports of raw material. Where efficient equipment is manufactured in India, availability is still a problem because it is not generally stocked by the dealers and there is invariably a long waiting period. For instance, though CFLs are manufactured in the country, they are available at only a few selected outlets.

Resource constraints: Due to limited resources most industries, with the exception of energy intensive industries, find it more attractive to invest scarce resources in expanding production facilities and marketing channels. Energy efficiency is generally given low priority by the industries where the share of energy costs is fairly low (say, around 10 percent).

Lack of information or awareness among consumers: One of the major constraints to implementation of DSM programs is the information gap. Consumers are not completely aware of the opportunities to improve energy efficiency available either within their own country and more important, outside their country. Often information on energy efficiency equipment is not available, and if available is rather general in nature. One of the options is to set up a comprehensive data bank on energy efficiency for various end-uses, for different processes or industries. This could be undertaken by industry associations, manufacturer associations, energy production companies or consumer groups. The mechanisms for dissemination may vary again depending upon the target group, such as newsletters, workshops, meetings, campaigns through the media, etc.. While some efforts are being undertaken, it needs to be more focussed and results oriented.

Energy labelling and standards: One important tool to increase consumer awareness is energy labelling. Labelling provides the consumer with

more information on energy consumption and is expected to encourage manufacturers to move towards products that are energy efficient, and consumers to purchase such products. In the U.S., several domestic appliances are required by law to display energy consumption labels. Some Asian countries--Korea, Philippines--have also initiated labelling programs for major electric products. In the area of standards, limited infrastructural facilities have been introduced to provide certification more quickly, and to carry out checks on the products manufactured all over the country.

Lack of expertise: Shortage of skilled manpower to provide technical assistance and training in identifying, installing and maintaining energy efficient equipment has hindered efficiency improvement efforts in India. Technical assistance capabilities need to be developed through training programs, setting up energy conservation cells at the state utilities, State Energy Development agencies, etc..

Quick payback requirements: Studies of consumer behavior reveal a fairly high private discount rate. If the energy saving device does not pay for itself in two years, consumers are not likely to invest in this equipment.

Risk aversion: End-users often have an aversion to taking risks associated with new technologies. It is in this context that there is a need to launch demonstration projects in areas where there are maximum benefits to the economy.

Small scale manufacturing market: Small scale industries play a dominant role in the Indian manufacturing industry. While appliances produced in the small scale sector are available at relatively low prices due to manual assembly, lower overheads, special protection from the government etc., there are concerns regarding the quality of these products. To ensure the quality and reliability of the equipment manufactured in the country, it is perhaps necessary to: (a) increase consumer awareness on energy efficiency and quality which would require the small industries to produce quality products; and (b) encourage small industries to have their products certified by the Bureau of Indian Standards.

Simple solutions not undertaken: Energy savings do not necessarily require the use of advanced technologies, or entire process changes. There are several solutions that can be undertaken by consumers which need either marginal investments or, in several cases, none at all. Initiating house keeping measures or improving operation and maintenance practices can bring about a 10-15 percent savings at the unit level. An analysis carried out on the recommendations made in energy audits (by TERI) indicated that out of 135 measures recommended, 103 measures related to actions that could be carried out with an investment of less than Rs 5,000,000 and with a payback of less than one year. Further, 51 measures related to operation and maintenance practices, where no investments were required. All these measures could yield

up to a 15 percent savings in energy consumption for that specific end-use. These measures are, however, not taken up in most cases due to lack of senior management commitment and the absence of trained manpower allocated specially for energy efficiency activities.

Lack of expertise for transfer of technology: It is not just enough to import energy efficient equipment; what is required is a transfer process which would enable design, manufacturing, and maintenance of this equipment in India. It is thus important that there is a larger plan to transfer the technology by collaborating with private research institutions, engineering colleges and universities in the area of energy efficiency. The need to be self-reliant must be accepted.

Problems with quality of power supply: Poor quality of power supply obligates manufacturers to produce and end-users to use equipment that can withstand large voltage fluctuations. However, such equipment is often less efficient than equipment designed to operate in a narrower voltage range.

6.6.2 Demand-side Management

The role of utilities in India in achieving energy efficiency through demand-side management measures is as yet quite uncertain. As mentioned in the earlier sections, the utilities are not convinced that DSM measures will bring about substantial reductions in new capacity additions. The main barriers relate to the following aspects.

Electricity pricing distortions: Electricity prices in India for most of the consumer categories (accounting for about 50 percent of consumption) are subsidized and therefore do not reflect true costs of energy use to the consumers. Electricity prices are regulated and are based on the historical accounting costs of the utility. Not only are the electricity rates well below the long-run marginal cost of generation and supply,[41] but for most of the utilities average revenue realized per unit is actually less than the average cost of supply.[42] The extent of subsidies is particularly large for agriculture at 80 to 100 percent, while subsidies for domestic consumers ranges between 40 and 60 percent.

Electricity tariffs in the short run must be linked to the cost of generation and supply of the utility based on certain norms of operation. In the long run, tariffs should be based on long run marginal costs (LRMC). Tariffs based strictly on LRMC could perhaps be adjusted for social considerations, consumer's ability to pay, etc.. In addition, innovative pricing mechanisms such as time-of-day rates to encourage consumers to shift consumption from peak hours (when electricity is more expensive) to off-peak hours (when electricity is relatively less expensive), interruptible options, curtailable rates, etc., should be initiated by the utilities for demand management.

Lack of experience in planning, designing and implementing DSM programs: Indian utilities do not have any experience in planning, designing and implementing DSM programs. Utility senior management is aware, to some extent, of the benefits of DSM and technologies that can reduce consumer demand, but they are not aware of how to plan, design and implement DSM programs. While the multilateral and bilateral financing institutions have been engaged in training efforts to increase the knowledge and awareness of DSM programs in utilities, this effort needs to be enlarged in scope. It may be necessary to designate senior officials from SEBs to utilities in the United States, for perhaps 3-6 months, to gain hands-on experience in DSM planning, designing and implementation.

Lack of utility commitment: Electric utilities in India are facing extreme pressure to provide electricity of the required quality and quantity to all consumers. At the same time, the utilities continue to adopt the traditional approach of adding new capacity to meet the growing demand. As a result, the limited resources available to the utilities are being stretched and diverted away from conservation efforts and towards adding new generation, transmission and distribution facilities. Utilities in India, though they do recognize the importance of DSM, are not yet committed to DSM.

Need for an integrated approach to power planning: Planning for the power sector and allocation of required funds in various Plans for the development of the power sector are controlled by the Government of India. Absence of an integrated resource planning approach which includes a simultaneous evaluation of demand side options has resulted in neglect of DSM as a serious option to adding capacity. DSM options must be formally included in the planning framework.

Absence of a national program on energy efficiency: The GOI has for the first time allocated Rs 1000 crores under the National Energy Efficiency Program for energy efficiency and DSM in the Eighth Five Year Plan (1992/93-1996/97). However, due to the lack of comprehensive programs, there is as yet no plan for utilizing these resources.

6.7 Conclusions and Recommendations

It is estimated that the Indian power sector can save 6.3 percent of the total electricity demand in 1996/97 and up to 8.21 percent in 2011/12 through energy efficiency and DSM options. Maximum benefits are estimated to come from the agriculture, domestic and commercial sectors. The potential for savings from the industrial sector is estimated at around 5-6 percent over the same years. These savings do not include major technological changes such as the membrane process in the chloro-alkali industry, new technology used for new aluminum units, etc., since these efficiency gains are already included in the forecasts carried out by the CEA. These gains are purely from carrying out

efficiency improvements on existing consumption and through limited investments in available process upgrades.

The success of DSM programs and actual efficiency gains ultimately depend on the participation rates of the end-users. The government, utilities, manufacturers and private sector all have an important role to play in overcoming the barriers that limit successful implementation of energy efficiency and DSM.

6.7.1 Role of State and Federal Governments

Electricity is a concurrent responsibility under the Indian Constitution. Hence, both the state and federal governments can undertake initiatives in this area. The governments have an important catalytic role in promoting energy efficiency through various economic and financial instruments and should formulate polices that would encourage greater electricity end-use efficiency. Possible strategies that could be considered by the government in promoting energy efficiency are discussed below.

6.7.1.1 Policy Initiatives

- Introduce the concept of integrated resource planning in the power sector planning framework. An evaluation of DSM options must be carried out, with specific realizable targets, and these must be integrated within the national and regional power plans.

- Develop a national program on energy efficiency. It is important for the Government to develop a national energy efficiency plan which includes realistic targets, identifies sources of finance, and establishes the necessary infrastructure for promoting energy efficiency. The role of the EMC is crucial in this regard. The state nodal agencies, who are the key players at the state level, need to effectively network with the EMC in this regard.

- Design and adopt appropriate energy conservation laws and regulations. The GOI has set up a Working Group on Selective Legislation for Energy Conservation with the basic objectives being to review and suggest amendments to the 14 select legislations concerning energy efficiency, to explore the desirability of comprehensive legislation for energy efficiency, and to suggest a draft model.

- Efficiency standards - Efficiency standards have been set for a wide variety of energy consuming equipment. There is a need to update these standards to take into account technological developments. The process of updating and revising standards needs to be streamlined. More important, there is an urgent need to set up infrastructure and facilities for providing certification quickly. The question of making certain standards mandatory needs to be addressed.

6.7.1.2 Economic and Financial Instruments

- Rationalized electricity pricing - Most SEBs have adopted increasing block tariffs for domestic and commercial consumers with the objective being to encourage electricity savings. It is important to ensure that the higher blocks of consumption are charged at rates close to marginal costs to reflect the true cost of electricity to consumers who can pay. As mentioned above, SEBs must seriously evaluate innovative options such as time-of-day tariffs, curtailable rates, etc. to manage the demand for electricity. The SEBs must improve upon the experiences of some utilities who have introduced time-of-day tariffs.

- Taxes and duties - The Government has offered several tax and duty reductions to promote energy efficiency. It is important that this list is reviewed and updated regularly to reflect technological developments. In this respect, there is need for closer coordination between the nodal ministries, research institutions, and the private sector.

- Offsetting financial barriers to energy efficient investments by offering selected, though usually temporary, financial inducements. Government could initiate demonstration projects in high priority areas such as lighting, retrofitting of agriculture pumpsets, etc., to provide the necessary financial impetus for such programs to take off.

6.7.1.3 Information Dissemination

Information dissemination is key to the success of energy efficiency and DSM programs in the country. While there are efforts ongoing by several organizations, there is a need to consolidate these efforts in order to ensure that there is maximum outreach.

- Labelling - A comprehensive study to determine the need for energy labelling on certain key electricity consuming appliances should be carried out. Based on this, a trial could be undertaken on selected appliances to study the effectiveness of labelling, before extending it to other appliances as well.

- Promote energy conservation through mass media-based awareness campaigns, calling for special efforts to recognize energy efficiency as a unique product that enables India to compete in the world markets. Case studies, product and consultant directories should be prepared and disseminated. Success stories of consumers adopting energy efficiency should be promoted. Sector specific promotional campaigns for major consuming sectors should be organized.

- Develop databases on energy use and efficiency improvement and make them available to the end-users. A beginning could perhaps be made by compiling information based on industrial energy audits carried out by various organizations in the country.

- Large scale training efforts for employees at various levels, managers, supervisors, shop floor workers, utility professionals, consumer groups etc.. A separate program for top management in industries should be undertaken to bring about total commitment towards energy efficiency.

- Exemplary role of government as end-user. The government is one of the largest users of energy. It is imperative that all decisions taken on energy consuming equipment incorporate energy efficiency as one of the key criteria. The practice of efficiency in government buildings, offices, and government residential colonies will have an enormous multiplier effect.

6.7.2 Utility

It is important that the utilities consider all supply and demand side options in an integrated framework to develop a least cost capacity expansion plan. Energy conservation cells must be set up in all the SEBs, where they do not exist at present. These cells must be headed by a Chief Engineer reporting directly to the Chairman, in order to provide the necessary importance to DSM and energy efficiency efforts. Apart from conducting energy audits, the objectives, role and tasks of the energy conservation cell must be clearly defined.

Initially, the utilities could start with information dissemination activities by organizing workshops, meetings with consumer forums, and dialogue with manufacturers on how to increase energy efficiency in all spheres of economic activity in the state. Simultaneously, all utilities must take steps to develop a comprehensive DSM plan for their states, in consultation and co-operation with industry associations, consumer forums, research organizations, etc.. Capacity building is a necessary prerequisite in order to undertake activities in this area.

The utilities with their extensive outreach can play a very important role in increasing consumer awareness and information dissemination. The utilities can, therefore, fulfill an important social responsibility in addition to the task of energy generation and supply.

6.7.3 Manufacturers

Manufacturers have often cited lack of demand as one of the reasons for not manufacturing energy efficient equipment. Low volumes lead to high costs and thus it is a question of breaking this circle of cost and volumes. In this context, it is appropriate to mention that manufacturers are making major investments in creating markets for several consumer durables. Energy efficiency has to be perceived as a product that needs to be marketed and the consumer made aware of their contribution to an energy efficient economy and in turn to a cleaner environment.

6.7.4 Role of Energy Service Companies

Several developing countries are moving towards a market economy through major liberalization efforts. With this, the private sector has an increasingly important role in promoting energy efficiency. One of the options is through energy service companies (ESCOs), who can offer a single point service to the consumer, by providing technical, financial and managerial expertise to the consumer.

The MoP and the EMC are the nodal organizations responsible for energy efficiency activities in the country. DSM, as a subset of energy efficiency, should be given a major thrust by initiating some demonstration projects in selected utilities in the country. Strong networking, preparation of a national program on energy efficiency and DSM with specific targets, and effective support by way of suitable fiscal and financial incentives and/or penalties are immediately required, if the country is to gain from the benefits of energy efficiency in the Ninth Plan and beyond.

Study on Energy Efficiency in Buildings, Volume 8: Utility Programs (Washington, D.C.. ACEEE, August 1990), pp. 103-112.

[18]Nadel, "Electric Utility Conservation Programs: A Review of the Lessons Taught by a Decade of Program Experience," in American Council for an Energy-Efficient Economy, *ACEEE 1990 Summer Study on Energy Efficiency in Buildings, Volume 8: Utility Programs* (Washington, D.C.: ACEEE, August 1990), p. 197.

[19]The most notable among the complaints has occurred in New York State. Industrial companies complained loudly that their competitors, by participating in utility programs, can gain an unfair competitive advantage if the non-participating company had already put in place similar technologies using their own funds. To add salt to the wounds, these nonparticipating companies are being asked to pay for the participant's programs.

[20]Marjorie McRae, "Will You Still Love Me Tomorrow...When Profits Depend on Program Performance Evaluations," in Canadian Electrical Association, *Demand-Side Management Conference; Proceedings* (Halifax, Nova Scotia, September 18-19, 1990), pp. 367-368.

[21]Carol E. Mulholland, Robert O'Brien, and Kevin Schoener, "Multi-Family Programs: Getting Around the Complex," in *Electric Power Research Institute's Sixth National Demand-Side Management Conference, Making a Difference*; *Proceedings* (Palo Alto, California: EPRI, March 1993).

[22]Discussion with an employee at Pacific Gas & Electric in California.

[23]Actually there are eight components: (i) training, (ii) motivation of trade associations and code officials, (iii) certification for the contractor or installer, (iv) monetary incentives, (v) testing requirements, (vi) marketing materials and assistance, (vii) code enforcement, and (viii) code staff assistance. The four points are deemed the most important.

[24]Karl Stum and Jeff Hammarlund, "Incorporating Improved HVAC Distribution Systems in Utility New Residential DSM Programs," in *Electric Power Research Institute's Sixth National Demand-Side Management Conference, Making a Difference*; *Proceedings* (Palo Alto, California: EPRI, March 1993).

[25]Masoud Almassi, "The Direct-Installation Approach to Energy Management," in *Electric Power Research Institute's Sixth National Demand-Side Management Conference, Making a Difference*; *Proceedings* (Palo Alto, California: EPRI, March 1993).

[26]Fred Avril and George D. Coburn, "Trade Allies: A Cost-Effective Resource," in *Electric Power Research Institute's Sixth National Demand-Side Management Conference, Making a Difference*; *Proceedings* (Palo Alto, California: EPRI, March 1993); and Carol E. Mulholland, Robert O'Brien, and Kevin Schoener, "Multi-Family Programs: Getting Around the Complex," in *Electric Power Research Institute's Sixth National Demand-Side Management Conference, Making a Difference*; *Proceedings* (Palo Alto, California: EPRI, March 1993).

[27]For detailed review of this process see Barbara D. Baker and Ellen F. Battle, *Demand-Side Management: Pushing Back Barriers*, CERI

Study No. 43 (Calgary, Alberta: Canadian Energy Research Institute, March 1992).

[28]There are volumes of literature in the area of regulation with specific focus on DSM. A study that takes a first look approach to regulation is Barbara Baker-Stariha, *Demand-Side Management for Natural Gas: Regulation and Implementation*, CERI Study No. 50 (Calgary, Alberta: CERI, July 1993). Another useful study is Steven Nadel, Michael W. Reid, and David R. Wolcott, eds., *Regulatory Incentives for Demand-Side Management* (Washington, D.C.: American Council for an Energy-Efficient Economy, 1992).

[29]Steven Nadel, Michael W. Reid, and David R. Wolcott, eds., *Regulatory Incentives for Demand-Side Management* (Washington, D.C.: American Council for an Energy-Efficient Economy, 1992).

[30]Several institutions have sections devoted to evaluating the effect of these technologies on power quality. For example, a recent conference sponsored by the major utilities in Alberta and their customers focussed entirely on the implications of DSM in power quality (The Fifth Alberta Exposition and Conference on Power Quality, "The Power Quality Implications of Demand-Side Management Initiatives," October 19-22, 1993, Calgary, Alberta).

[31]Samuel Baldwin, Energy-Efficient Electric Motor Drive Systems," in *Electricity: Efficient End-use and New Generation Technologies and Their Planning Implications*, edited by Thomas B. Johansson, Birgit Bodlund, and Robert H. Williams (Lund, Sweden: Lund University Press, 1989), p. 49.

[32]World Bank, "Energy Efficiency and Conservation in the Developing World" (1993).

[33]TERI, "Energy Efficiency of Domestic Appliance" (1991).

[34]Asian Development Bank, "Energy End-use: An Environmentally Sound Development Pathway" (1993).

[35]Asian Development Bank, "Energy End-use: An Environmentally Sound Development Pathway" (1993).

[36]TERI, "Energy Efficiency of Domestic Appliance" (1991).

[37]U.S.AID, "Opportunities for Improving End-use Efficiency in India" (1991).

[38]U.S.AID, "Opportunities for Improving End-use Efficiency in India" (1991).

[39]S.M. Patel, "Low Cost and Quick Yielding Measure for Energy Conservation in Agriculture Pumps," *Pacific and Asian Journal of Energy*, Vol 2, No.1 (1988)

[40]EMC, "Study on Improving Efficiency of Agriculture Pumping Systems for Energy conservation" (1992).

[41]In the Maharashtra State Electricity Board, the average revenue realized from domestic, commercial, agriculture, and low-tension industries was less than the long run marginal cost of generation and supply of electricity to these consumer categories (TERI 1992).

[42]In 1991/92, the average revenue realized for all utilities was 81 paise/kWh, while the average cost of generation and supply was 105 paise/kWh.

7.2 Base Case Development Scenario

As discussed in previous chapters, the electric power sector in India has been expanding at a rapid pace over the last four decades. Serious concerns have been raised as to the ability of the Indian government to sustain this pace of development, and the physical ability of the electric power system to meet future demand for electricity services.

The Base Case represents a Business as Usual development strategy for the power sector. Other than limitations on expansion of hydro-electric generation capacity up to 80 GW; natural gas utilization restricted to a maximum of 14,700 million cubic meters (mcm) per annum; and new nuclear capacity restricted to an additional 27 GW by 2021; this is an unconstrained, least cost development scenario which meets all projected electricity demand. The question being addressed is, "How large could the Indian electric power sector become, and with what configuration, if current practices were continued without constraints on development?"

A summary of the scenario results is provided in Table 7.1. From the 1991 level of 69 GW of capacity, the system expands over eight-fold to exceed 560 GW in 2021. While all energy requirements are met, there is a capacity shortfall of 24.9 GW to meet peak demand. Coal-fired generation increases from 45.5 GW to over 477 GW, with coal consumption rising from 129 million tonnes (Mt) to over 1393 Mt in 2021. Second to growth in coal-fired capacity is growth in gas-fired generation, which increases almost ten-fold, from 2.6 GW in 1991 to over 24 GW in 2021. Of the total hydro-electric potential of 80 GW, only 54 GW is developed by 2021, registering a 2.8 times increase over installed hydro-electric capacity in 1991. The share of hydro in the total installed capacity mix declines from 27.8 percent in 1991 to 9.6 percent in 2021, primarily due to cost considerations.

The average annual share of Indian gross domestic product (GDP) required to finance this massive expansion in generation capacity is close to 4.2 percent, reaching Rs 563,328 crores in 2021. This compared to an historical average annual investment of 3.2 percent of GDP in the electric sector.

The impact on emissions is considerable. Particulates more than double over the 1991 to 2021 period, and emissions of CO_2, SO_2, and NO_x increase close to eleven times their 1991 levels by 2021.

7.3 Reference Case Scenario

The development scenario described in the Base Case is clearly unrealistic for India. In particular, the financial investment required to underwrite the implied capacity expansion would necessitate an unprecedented diversion of national income to the power sector, assuming that the entire financial investment for power sector development were to be provided by the government.

Table 7.1

Base Case (Business As Usual)

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Installed Generation (MW)								
Coal	45509	46478	81768	133626	214242	334196	477209	10.5
Nuclear	1785	2814	4831	4751	4704	4690	4690	2.6
Natural Gas	2587	13191	20355	21036	22249	24810	24813	9.6
Hydro	19189	26409	35827	41177	47086	50871	53960	2.8
Subtotal	69070	88893	142782	200590	288281	414567	560672	8.1
% Hydro	27.8%	29.7%	25.1%	20.5%	16.3%	12.3%	9.6%	
Capacity Shortfall	0	0	0	0	0	0	0	
% Gen. Subtotal	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	4.4%	
Total Capacity Required	69070	88893	142782	200590	288281	414567	585549	8.5
Capital Investment (Rupee Crores/Time Period)	0	69370	191816	211667	315041	447831	563328	
Installed Generation (MW)								
Decentralized Power	0	0	0	0	0	0	0	
Demand-side Management	0	0	0	0	0	0	0	
Cogeneration	0	0	0	0	0	0	0	
Clean Coal Technologies	0	0	0	0	0	0	0	
Energy Resource Consumption								
Hydro (MW)	9344	13452	18774	21146	22177	19753	26901	2.9
Coal ('000 tonnes)	129282	162902	256251	395251	622407	974333	1393503	10.8
Natural Gas (millions m^3)	3322	8818	12490	12761	13350	14699	14700	4.4
Fuel Oil ('000 m^3)	911	1160	1962	3123	4991	7884	11329	12.4
Nuclear Fuel ('000 kg U)	856	1394	2293	1926	1625	1619	1619	1.9
Environmental Emissions								
Particulates ('000 tonnes)	4136978	4943559	4671239	4847121	5843211	7447070	9420847	2.3
CO_2 ('000 tonnes)	224793	292551	457930	693645	1078980	1676857	2385795	10.6
SO_2 ('000 tonnes)	1230	1605	2532	3856	6023	9382	13367	10.9
NO_x ('000 tonnes)	1193	1541	2413	3668	5721	8905	12683	10.6
Nuclear Waste ('000 m^3)	9945	16189	26630	22363	18868	18803	18803	1.9

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

For purposes of comparison with alternative development scenarios, it was decided to generate a Reference Case scenario based on a realistic set of initial constraints for power sector development. The structure of this scenario is the same as the Base Case, except:

- a financial constraint is imposed limiting capital investment in the power sector to historical levels of 3.2 percent of GDP forecast for India;

- a coal constraint is imposed limiting coal available for electric power generation to 406 Mt in 2011 and 650 MT in 2021. This constraint is imposed to capture both the physical capabilities of the mining and transportation network to provide coal volumes, and the declining quality of available coal; and

- renewable sources of electricity supply are assumed as part of the available generation mix.

The results of the Reference Case scenario are provided in Table 7.2. Investment reaches Rs 340,617 crores in 2021, compared to Rs 563,328 crores under the Base Case, a reduction of 40 percent. Total installed capacity increases 4.6 times from 1991 levels to 319.2 GW in 2021. Coal-fired generation expansion is constrained significantly relative to the Base Case, reaching 191 GW in 2021 compared to 477 GW in the Base Case. The shortfall is partly made up by a significant expansion in nuclear generation, which increases 16 times the 1991 level to total 28.5 GW in 2021, *versus* 4.7 GW in the Base Case.

Table 7.2 contains an element labelled Capacity Shortfall, which is the difference between the installed capacity required to meet the demand and actual installed capacity. This is a measure of the electricity demand which is not satisfied under this particular development scenario. The row labelled Total Capacity Required, therefore, represents the capacity which would be required under this scenario to meet projected demand for energy services. Total system capacity requirements reach 544 GW in 2021.

A comparison of the difference between the Reference Case and Base Case scenario results is provided in Table 7.3. The following points are important:

- Shortfall capacity represents 41 percent of total capacity required in 2021. This is the major impact arising out of constraining coal and financial resources available.

- The share of hydro increases substantially to 24 percent in the Reference Case compared to 9.6 percent in the Base Case.

- Due to fuel constraints and limited resource availability, there is a substantial reduction in coal-based generation capacity, and an associated reduction in emissions.

Table 7.2

Reference Case

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Installed Generation (MW)								
Coal	45509	54948	67327	91502	125421	161309	191429	4.2
Nuclear	1785	3214	6131	12051	18004	25490	28490	16.0
Natural Gas	2587	2485	20483	21010	22027	22024	22777	8.8
Hydro	19189	27168	35261	46860	59415	70000	76460	4.0
Subtotal	69070	87815	129203	171424	224868	278823	319156	4.6
% Hydro	27.8%	30.9%	27.3%	27.3%	26.4%	25.1%	24.0%	
Capacity Shortfall	0	0	8565	18305	45745	105777	224584	
% Gen. Subtotal	0.0%	0.0%	6.6%	10.7%	20.3%	37.9%	70.4%	
Total Capacity Required	69070	87815	137769	189729	270613	384601	543740	7.9
Capital Investment (Rupee Crores/Time Period)	0	80000	147730	197700	264560	316051	340617	
Installed Generation (MW)								
Decentralized Power	0	500	3200	4800	6400	8000	9600	
Demand-side Management	0	0	0	0	0	0	0	
Cogeneration	0	0	0	0	0	0	0	
Clean Coal Technologies	0	0	0	0	0	0	0	
Energy Resource Consumption								
Hydro (MW)	9344	13507	18405	25087	32373	38620	42431	4.5
Coal ('000 tonnes)	129282	168949	246024	320000	406000	516000	650000	5.0
Natural Gas (millions m^3)	3322	3190	12558	13716	14700	14700	14700	4.4
Fuel Oil ('000 m^3)	910	1236	1845	2479	3224	4142	5240	5.8
Nuclear Fuel ('000 kg U)	857	1387	3122	6203	9299	13192	14751	17.2
Environmental Emissions								
Particulates ('000 tonnes)	4136978	4372912	5369262	5173031	4755311	5139740	5791807	1.4
CO_2 ('000 tonnes)	224793	291619	440645	568188	715844	902046	1128628	5.0
SO_2 ('000 tonnes)	1230	1608	2435	3148	3975	5020	6296	5.1
NO_x ('000 tonnes)	1193	1549	2322	2998	3781	4771	5979	5.0
Nuclear Waste ('000 m^3)	9945	16104	36247	72015	107967	153157	171264	17.2

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council, and Tata Energy Research Institute.

Table 7.3

Reference Case Minus Base Case

Year	1991	1996	2001	2006	2011	2016	2021
Installed Generation (MW)							
Coal	0	8470	-14440	-42123	-88820	-172887	-285780
Nuclear	0	400	1300	7300	13300	20800	23800
Natural Gas	0	-10706	128	-25	-221	-2786	-2035
Hydro	0	758	-566	5683	12329	19129	22500
Subtotal	0	-1077	-13578	-29166	-63413	-135744	-241515
Capacity Shortfall	0	0	8565	18305	45745	105777	199706
Total Capacity Required	0	-1077	-5013	-10860	-17668	-29966	-41809
Capital Investment (Rupee Crores/Time Period)	0	10629	-44086	-13967	-50481	-131779	-222711
Installed Generation (MW)							
Decentralized Power	0	500	3200	4800	6400	8000	9600
Demand-side Management	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0
Clean Coal Technologies	0	0	0	0	0	0	0
Energy Resource Consumption							
Hydro (MW)	0	55	-369	3941	10196	18867	15530
Coal ('000 tonnes)	0	6047	-10227	-75251	-216407	-458333	-743503
Natural Gas (millions m^3)	0	-5628	68	955	1350	1	0
Fuel Oil ('000 m^3)	-0	76	-116	-643	-1766	-3741	-6088
Nuclear Fuel ('000 kg U)	0	-7	828	4276	7673	11572	13131
Environmental Emissions							
Particulates ('000 tonnes)	0	-570647	698023	325910	-1087900	-2307330	-3629040
CO_2 ('000 tonnes)	0	-932	-17285	-125457	-363136	-774811	-1257167
SO_2 ('000 tonnes)	-0	2	-97	-708	-2048	-4362	-7071
NO_x ('000 tonnes)	-0	7	-91	-670	-1940	-4134	-6704
Nuclear Waste ('000 m^3)	0	-85	9617	49652	89099	134354	152461

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council, and Tata Energy Research Institute.

As mentioned, this scenario and those discussed below introduce a series of renewable generation options to the array of alternative generation sources available to the model. As shown in Table 7.4, 9600 MW of renewable capacity comes on stream by 2021. The principal sources are biogas (3000 MW), micro hydroelectric (3600 MW), and wind power (3000 MW).

Table 7.4

Reference Case
Decentralized Generation By Region in 2021
(MW)

	North-east	North	East	West	South	Total
Biogasification	900	600	0	900	600	3000
Solar Thermal	0	0	0	0	0	0
Micro Hydroelectric	360	720	360	0	2160	3600
Photovoltaic	0	0	0	0	0	0
Wind	0	0	0	900	2100	3000
Total	1260	1320	360	1800	4860	9600

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council, and Tata Energy Research Institute.

Figure 7.1 displays installed generation in the Reference Case as a ratio of Base Case levels for 2021 together with capital investment. As shown in this figure, coal capacity and capital investment fall 60 and 40 percent, respectively, from 2021 Base Case levels. Nuclear capacity, however, is over six times, and hydro capacity 1.4 times, greater than the Base Case levels.

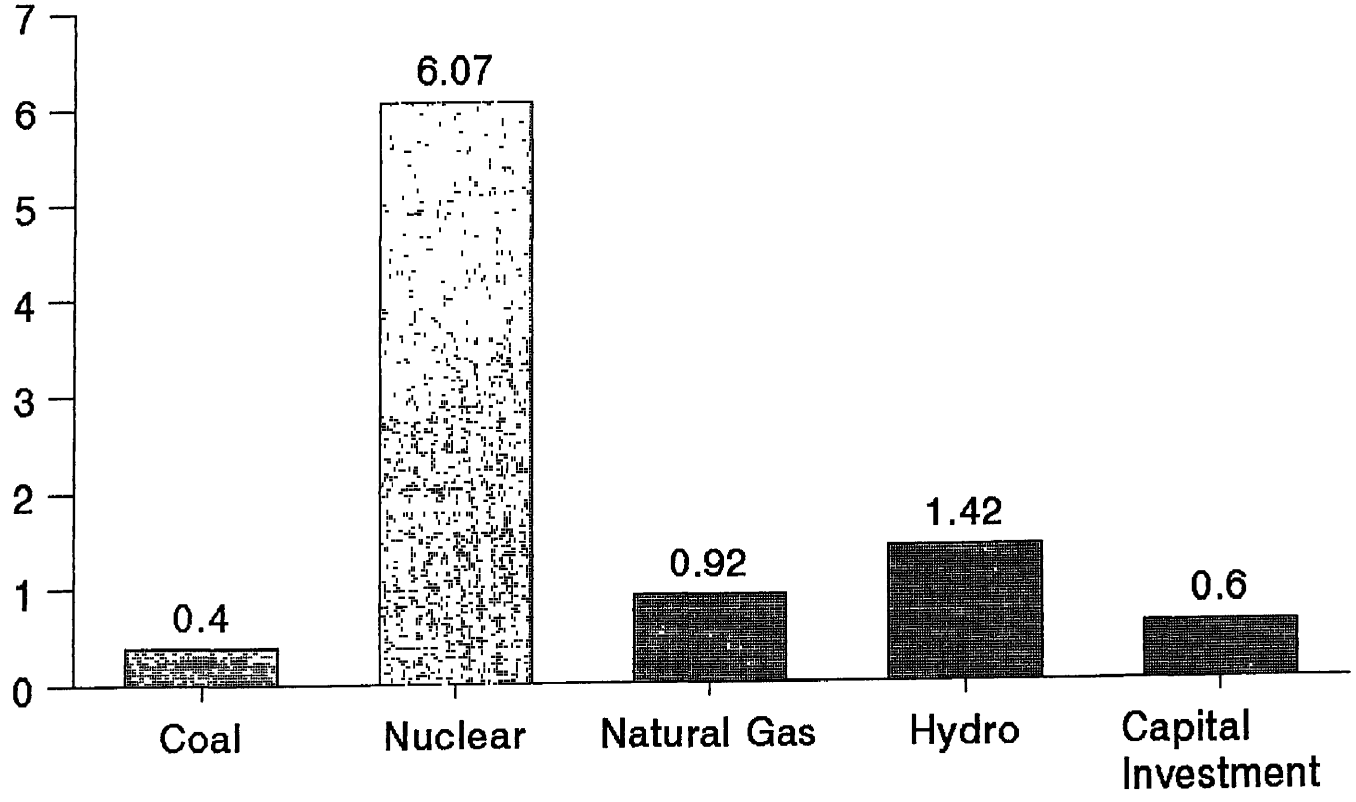
All the scenarios discussed below are compared with the Reference Case. It is important to note that when the constrained upper bound for coal availability is reached, there will not be any significant difference in the total level of emissions. Hence, comparison of emissions per kWh is a more appropriate indicator.

7.4 Demand-side Management Scenario

The DSM scenario makes available to the system a number of DSM options, discussed in Chapter 6 of the study. The impact of the DSM options is greatest during the system peak, allowing the postponement of expensive peaking capacity in favor of more base load capacity. The result is a better capability to meet projected system demand.

A summary of the DSM scenario results is provided in Table 7.5, with differences from the Reference Case provided in Table 7.6. Looking at aggregate system size, there is only a marginal difference in the two scenarios,

Figure 7.1
Reference Case as Ratio of
Base Case in 2021



SOURCE: Canadian Energy Research Institute (January 1995).

but the DSM option lowers the capacity shortfall by 50 GW, reducing the total required capacity by 50.5 GW by the end of the projection period. DSM capacity reaches 19.5 GW in 2021. Capacity shortfalls relative to projected demand are eliminated until 2006, a significant improvement over the Reference Case. Installed capacity increases 4.6 times by 2021 relative to the 1991 level. It is important to note that DSM does not use capital from the financial constraint imposed on this scenario. Since all resources are used to the limit, DSM reduces the shortfall. The emissions impact of DSM is felt most in the early projection periods. All emissions levels are reduced relative to the reference case, over the 1991-2006 period.

7.5 Clean Coal Technologies Scenario

From the list of CCTs discussed in Chapter 3, Integrated Gasification Combined Cycle (IGCC), Pressurized Fluidized Bed Combustion (PFBC), and Atmospheric Fluidized Bed Combustion (AFBC) were selected as candidate technologies, owing to their cost competitiveness and availability over the projection period and their potential for meeting emission control requirements. As shown in Tables 7.7 and 7.8, the CCT options are introduced into the electric power development scenario after 1996. Installed capacity of power generation from CCTs totals 134 GW in 2021. The capacity shortfall under this scenario is estimated at 199 GW in 2021, which is 26 GW lower than that in the Reference Case.

Emissions of all forms, excepting nuclear waste, are down significantly from Reference Case levels over the projection period. Particulate emissions in 2021 are 18 percent lower compared to the Reference Case in the final reporting period due to the higher efficiency of IGCC units. SO_2 and NO_x emissions are 3.3 Mt and 2.4 Mt per annum less than Reference Case levels in 2021.

Emissions per MW comes down from:

- 9.0 tonne/MW of CO_2 to 7.2 tonne/MW of CO_2.
- 50.3 tonne/MW of SO_2 to 21.5 tonne/MW of SO_2;
- 47.7 tonne/MW of No_x to 25.4 tonne/MW of NO_x; and
- 46.2 tonne/MW of particulates under the Reference case to 33.8 tonne/MW of particulates under the CCT scenario.

Table 7.5

Demand-side Management Scenario

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Installed Generation (MW)								
Coal	45509	48813	63085	94414	132085	161596	191388	4.2
Nuclear	1785	3214	6131	12051	18004	25490	28490	16.0
Natural Gas	2587	2485	19789	19946	22619	22616	22616	8.7
Hydro	19189	28191	37624	47645	60000	70000	76020	4.0
Subtotal	69070	82703	126629	174057	232709	279703	318514	4.6
% Hydro	27.8%	34.1%	29.7%	27.4%	25.8%	25.0%	23.9%	
Capacity Shortfall	0	0	0	577	12472	67759	174700	
% Gen. Subtotal	0.0%	0.0%	0.0%	0.3%	5.4%	24.2%	54.8%	
Total Capacity Required	69070	82703	126629	174634	245182	347462	493214	7.1
Installed Generation (MW)								
Decentralized Power	0	500	2200	3750	6400	8000	9600	
Demand-side Management	0	2089.2	4893	7250	11129	14702	19500	
Cogeneration	0	0	0	0	0	0	0	
Clean Coal Technologies	0	0	0	0	0	0	0	
Energy Resource Consumption								
Hydro (MW)	9344	14089	19820	25306	32723	38620	42167	4.5
Coal ('000 tonnes)	129282	152045	210184	291816	406000	516000	650000	5.0
Natural Gas (millions m^3)	3322	3190	12193	12628	14700	14700	14700	4.4
Fuel Oil ('000 m^3)	911	1093	1567	2269	3219	4139	5236	5.7
Nuclear Fuel (000 kg U)	857	1523	3122	5785	9299	13192	14751	17.2
Environmental Emissions								
Particulates ('000 tonnes)	4136978	4377781	4785887	4482879	4786761	5159775	5814010	1.4
CO_2 ('000 tonnes)	224793	263007	379375	518439	715768	901998	1128574	5.0
SO_2 ('000 tonnes)	1230	1447	2090	2868	3975	5020	6294	5.1
NO_x ('000 tonnes)	1193	1396	1995	2734	3781	4771	5979	5.0
Nuclear Waste ('000 m^3)	9945	17679	36247	67161	107967	153157	171264	17.2

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.6

DSM Scenario Minus Reference Case

Year	1991	1996	2001	2006	2011	2016	2021
Installed Generation (MW)							
Coal	0	-6135	-4242	2912	6664	287	-40
Nuclear	0	0	0	0	0	0	0
Natural Gas	0	0	-694	-1064	592	592	-161
Hydro	0	1022	2362	785	585	0	-440
Subtotal	0	-5112	-2573	2633	7841	879	-642
Capacity Shortfall	0	0	-8565	-17728	-33272	-38018	-49884
Total Capacity Required	0	-5112	-11139	-15095	-25430	-37138	-50526
Installed Generation (MW)							
Decentralized Power	0	0	-1000	-1050	0	0	0
Demand-side Management	0	2089	4893	7250	11129	14702	19500
Cogeneration	0	0	0	0	0	0	0
Clean Coal Technologies	0	0	0	0	0	0	0
Energy Resource Consumption							
Hydro (MW)	0	582	1415	219	350	0	-264
Coal ('000 tonnes)	0	-16904	-35840	-28184	0	0	0
Natural Gas (millions m^3)	0	0	-365	-1088	0	0	0
Fuel Oil ('000 m^3)	0	-143	-277	-209	-5	-3	-3
Nuclear Fuel ('000 kg U)	0	136	0	-418	0	0	0
Environmental Emissions							
Particulates ('000 tonnes)	0	4869	-583375	-690152	31450	20035	22203
CO_2 ('000 tonnes)	0	-28612	-61270	-49749	-76	-48	-54
SO_2 ('000 tonnes)	0	-161	-344	-279	0	0	-1
NO_x ('000 tonnes)	0	-152	-326	-263	0	0	0
Nuclear Waste ('000 m^3)	0	1575	0	-4854	0	0	0

SOURCES: ELITE, December 1994, Canadian Energy Research Institute; Alberta Research Council, and Tata Energy Research Institute.

Table 7.7

Clean Coal Technology Scenario

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Installed Generation (MW)								
Coal	45509	55189	66853	96891	125954	170496	216690	4.8
Nuclear	1785	3214	6131	12051	18004	25490	28490	16.0
Natural Gas	2587	2485	20572	21100	21405	21554	22902	8.9
Hydro	19189	26966	35459	44080	56435	67020	75820	4.0
Subtotal	69070	87854	129016	174122	221798	284560	343903	5.0
% Hydro	27.8%	30.7%	27.5%	25.3%	25.4%	23.6%	22.0%	
Capacity Shortfall	0	0	8567	15961	45291	96317	198686	
% of Gen. Subtotal	0.0%	0.0%	6.6%	9.2%	20.4%	33.8%	57.8%	
Total Capacity Required	69070	87854	137583	190084	267090	380878	542589	7.9
Installed Generation (MW)								
Decentralized Power	0	444	3200	4800	6400	8000	9600	
Demand-side Management	0	0	0	0	0	0	0	
Cogeneration	0	0	0	0	0	0	0	
Clean Coal Technologies	0	1365	1668	12176	42413	87816	134011	
Energy Resource Consumption								
Hydro (MW)	9344	13386	18523	23421	30587	36834	42047	4.5
Coal ('000 tonnes)	129282	169053	243493	320000	406000	516000	650000	5.0
Natural Gas (millions m^3)	3322	3190	12836	14084	14700	14700	14700	4.4
Fuel Oil ('000 m^3)	910	1203	1783	2206	2190	2021	2041	2.2
Nuclear Fuel ('000 kg U)	857	1398	3122	6203	9299	13192	14751	17.2
Environmental Emissions								
Particulates ('000 tonnes)	4136978	4357888	632 753	4833057	4854890	4462940	4715235	1.1
CO_2 ('000 tonnes)	224793	291750	414 154	568955	715485	901227	1127785	5.0
SO_2 ('000 tonnes)	1230	1573	2 761	2856	2926	2833	2992	2.4
NO_x ('000 tonnes)	1193	1524	1 777	2781	3005	3158	3534	3.0
Nuclear Waste ('000 m^3)	9945	16228	9 087	72015	107967	153157	171264	17.2

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.8

Clean Coal Technology Scenario Minus Reference Scenario

Year	1991	1996	2001	2006	2011	2016	2021
<u>Installed Generation (MW)</u>							
Coal	0	241	-474	5389	532	9186	25261
Nuclear	0	0	0	0	0	0	0
Natural Gas	0	0	89	89	-622	-469	125
Hydro	0	-202	197	-2780	-2980	-2980	-640
Subtotal	0	38	-187	2698	-3069	5737	24746
Capacity Shortfall	0	0	1	-2344	-453	-9460	-25898
Total Capacity Required	0	38	-185	354	-3522	-3723	-1151
<u>Installed Generation (MW)</u>							
Decentralized Power	0	-55	0	0	0	0	0
Demand-side Management	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0
Clean Coal Technologies	0	1365	1668	12176	42413	87816	134011
<u>Energy Resource Consumption</u>							
Hydro (MW)	0	-121	118	-1666	-1786	-1786	-384
Coal ('000 tonnes)	0	104	-2531	0	0	0	0
Natural Gas (millions m^3)	0	0	278	368	0	0	0
Fuel Oil ('000 m^3)	0	-32	-61	-273	-1034	-2121	-3199
Nuclear Fuel ('000 kg U)	0	11	0	0	0	0	0
<u>Environmental Emissions</u>							
Particulates ('000 tonnes)	0	-15024	-28554	-339974	99579	-676800	-1076572
CO_2 ('000 tonnes)	0	131	-3778	767	-359	-819	-843
SO_2 ('000 tonnes)	0	-34	-64	-291	-1048	-2186	-3303
NO_x ('000 tonnes)	0	-25	-53	-217	-775	-1613	-2444
Nuclear Waste ('000 m^3)	0	124	0	0	0	0	0

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy

7.6 Cogeneration Scenario

Cogeneration results are displayed in Tables 7.9 and 7.10.

About 45 GW of additional capacity is available from cogeneration in 2021, thus reducing the shortfall in installed capacity requirement from 70 percent in the Reference case to 51 percent in the Cogeneration option.

Of the total cogeneration capacity that comes on stream, nearly 90 percent is bagasse based cogeneration in sugar mills. The remaining is waste heat recovery in other energy intensive industries. Bagasse-based cogeneration is neutral in terms of CO_2 emissions and can save about 1.24 kg of CO_2 per kWh of electricity. There is not much difference in the overall levels of emissions under the Cogeneration and Reference Cases, which should be expected as coal and natural gas consumption are the same under the two scenarios (i.e. upper bound of fuel available for power sector). It is important to note, however, that emissions per MW are reduced significantly in the Cogeneration case. CO_2 emissions per MW decline from 9.0 tonne/MW in the Reference case to 7.2 tonne/MW in the Cogeneration case. Similarly, emissions of SO_x fall from 50.3 tonne/MW to 40.4 tonne/MW, and that of NO_x from 46.2 tonne/MW to 37.3 tonne/MW.

7.7 Reduced Losses

The high levels of T & D losses, averaging about 22 percent of total generation at the busbar, is an issue of major concern for the Indian power system Indeed, reducing these losses to more acceptable levels is estimated to be one of the most economic options for improving both system performance and reliability.

Tables 7.11 and 7.12 summarize the impact of reducing system T & D losses from 22 percent to 15 percent on an across-India basis. The installed capacity for this case is virtually the same as the Reference Case in 2021. However, the capacity shortfall is down significantly (34 GW) by 2021 compared to the Reference Case.

The major reduction in emissions recorded in the 1991-2006 period (see Table 7 12) is reversed in the final reporting periods.

7.8 Optimistic Scenario

The preceding scenarios have analyzed the introduction of alternative technologies and system enhancements on an independent basis. Assuming that initiatives could be undertaken on all these options simultaneously, it is appropriate to assess a scenario that combines <u>all</u> the above planning options.

Table 7.9

Cogeneration Scenario

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Installed Generation (MW)								
Coal	45509	49941	62392	91425	122540	159629	191401	4.2
Nuclear	1785	3214	4831	10751	16704	24190	28490	16.0
Natural Gas	2587	2485	20651	21178	21636	21783	23470	9.1
Hydro	19189	26744	34737	43027	54182	65167	74098	3.9
Other	0	6615	9427	13799	20844	30955	45475	
Subtotal	69070	88999	132039	180181	235906	301725	362934	5.3
% Hydro	27.8%	30.0%	26.3%	23.9%	23.0%	21.6%	20.4%	
Capacity Shortfall	0	0	7323	13216	35303	84490	185256	
% Gen. Subtotal	0.0%	0.0%	5.5%	7.3%	15.0%	28.0%	51.0%	
Total Capacity Required	69070	88999	139362	193398	271210	386215	548191	7.9
Installed Generation (MW)								
Decentralized Power	0	100	3200	4800	6400	8000	9600	
Demand-side Management	0	0	0	0	0	0	0	
Cogeneration	0	6615	9427	13799	20844	30955	45475	
Clean Coal Technologies	0	0	0	0	0	0	0	
Energy Resource Consumption								
Hydro (MW)	9344	13452	18107	22806	29254	35740	41032	4.4
Coal ('000 tonnes)	129282	172000	228564	320000	406000	516000	650000	5.0
Natural Gas (millions m^3)	3322	3190	12646	13827	14443	14700	14700	4.4
Fuel Oil ('000 m^3)	910	1239	1701	2480	3204	4138	5237	5.8
Nuclear Fuel ('000 kg U)	857	1602	2446	5527	8624	12516	14751	17.2
Environmental Emissions								
Particulates ('000 tonnes)	4136978	4896904	5287901	5173227	5208129	5165860	5807030	1.4
CO_2 ('000 tonnes)	224795	296677	411291	568430	715203	901983	1128591	5.0
SO_2 ('000 tonnes)	1230	1636	2270	3149	3973	5020	6298	5.1
NO_x ('000 tonnes)	1193	1576	2164	2998	3778	4771	5979	5.0
Nuclear Waste ('000 m^3)	9945	18603	28401	64169	100121	145310	171264	17.2

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.10

Cogeneration Scenario Minus Reference Case

Year	1991	1996	2001	2006	2011	2016	2021
Installed Generation (MW)							
Coal	0	-5007	-4935	-76	-2881	-1679	-28
Nuclear	0	0	-1300	-1300	-1300	-1300	0
Natural Gas	0	0	168	168	-391	-240	692
Hydro	0	-424	-524	-3832	-5232	-4832	-2361
Other	0	6615	9427	13799	20844	30955	45475
Subtotal	0	1183	2835	8757	11038	22902	43777
Capacity Shortfall	0	0	-1242	-5089	-10441	-21287	-39327
Total Capacity Required	0	1183	1593	3668	597	1614	4450
Installed Generation (MW)							
Decentralized Power	0	-400	0	0	0	0	0
Demand-side Management	0	0	0	0	0	0	0
Cogeneration	0	6615	9427	13799	20844	30955	45475
Clean Coal Technologies	0	0	0	0	0	0	0
Energy Resource Consumption							
Hydro (MW)	0	-55	-298	-2281	-3119	-2880	-1399
Coal ('000 tonnes)	0	3051	-17460	0	0	0	0
Natural Gas (millions m^3)	0	0	88	111	-257	0	0
Fuel Oil ('000 m^3)	0	2	-143	1	-20	-4	-2
Nuclear Fuel ('000 kg U)	0	215	-676	-676	-675	-676	0
Environmental Emissions							
Particulates ('000 tonnes)	0	523992	-81361	196	452818	26120	15223
CO_2 ('000 tonnes)	0	5058	-29354	242	-641	-63	-37
SO_2 ('000 tonnes)	0	28	-165	1	-1	0	2
NO_x ('000 tonnes)	0	27	-157	0	-2	0	0
Nuclear Waste ('000 m^3)	0	2499	-7846	-7846	-7846	-7847	0

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.11

Reduced Losses Scenario

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Installed Generation (MW)								
Coal	45509	49364	67032	98392	127177	161566	191392	4.2
Nuclear	1785	3214	6131	12051	18004	25490	28490	16.0
Natural Gas	2587	2485	19789	19946	22619	22616	22616	8.7
Hydro	19189	29364	38017	47645	60000	69885	76026	4.0
Subtotal	69070	84428	130970	178035	227800	279558	318524	4.6
% Hydro	27.8%	34.8%	29.0%	26.8%	26.3%	25.0%	23.9%	
Capacity Shortfall	0	0	0	3239	26999	81510	190519	
% Gen. Subtotal	0.0%	0.0%	0.0%	1.8%	11.9%	29.2%	59.8%	
Total Capacity Required	69070	84428	130970	181274	254800	361068	509044	7.4
Installed Generation (MW)								
Decentralized Power	0	0	2200	4800	6400	8000	9600	
Demand-side Management	0	0	0	0	0	0	0	
Cogeneration	0	0	0	0	0	0	0	
Clean Coal Technologies	0	0	0	0	0	0	0	
Energy Resource Consumption								
Hydro (MW)	9344	14477	20056	25557	32723	38551	42171	4.5
Coal ('000 tonnes)	129282	149725	215444	310780	406000	516000	650000	5.0
Natural Gas (millions m^3)	3322	3190	12193	12628	14700	14700	14700	4.4
Fuel Oil ('000 m^3)	911	1079	1620	2419	3222	4139	5236	5.7
Nuclear Fuel ('000 kg U)	856	1456	3122	4636	9299	13192	14751	17.2
Environmental Emissions								
Particulates ('000 tonnes)	4136978	4257350	4606628	4773921	4766722	5157677	5811684	1.4
CO_2 ('000 tonnes)	224793	259107	388283	550503	715817	902003	1128580	5.0
SO_2 ('000 tonnes)	1230	1424	2141	3049	3975	5020	6294	5.1
NO_x ('000 tonnes)	1193	1376	2043	2905	3780	4771	5979	5.0
Nuclear Waste ('000 m^3)	9945	16906	36247	53829	107967	153157	171264	17.2

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.12

Reduced Losses Minus Reference Case

Year	1991	1996	2001	2006	2011	2016	2021
Installed Generation (MW)							
Coal	0	-5583	-295	6890	1755	257	-36
Nuclear	0	0	0	0	0	0	0
Natural Gas	0	0	-694	-1064	592	592	-161
Hydro	0	2196	2756	785	585	-115	-433
Subtotal	0	-3387	1767	6611	2932	734	-631
Capacity Shortfall	0	0	-8565	-15066	-18745	-24267	-34064
Total Capacity Required	0	-3387	-6798	-8455	-15812	-23532	-34696
Installed Generation (MW)							
Decentralized Power	0	-500	-1000	0	0	0	0
Demand-side Management	0	0	0	0	0	0	0
Cogeneration	0	0	0	0	0	0	0
Clean Coal Technologies	0	0	0	0	0	0	0
Energy Resource Consumption							
Hydro (MW)	0	970	1651	470	350	-69	-260
Coal ('000 tonnes)	0	-19224	-30580	-9220	0	0	0
Natural Gas (millions m^3)	0	0	-365	-1088	0	0	0
Fuel Oil ('000 m^3)	0	-157	-225	-60	-2	-3	-3
Nuclear Fuel ('000 kg U)	-0	69	0	-1567	0	0	0
Environmental Emissions							
Particulates ('000 tonnes)	0	-115562	-762634	-399110	11411	17937	19877
CO_2 ('000 tonnes)	0	-32512	-52362	-17685	-27	-43	-48
SO_2 ('000 tonnes)	0	-183	-293	-98	0	0	-1
NO_x ('000 tonnes)	0	-172	-278	-92	-0	0	0
Nuclear Waste ('000 m^3)	0	802	0	-18186	0	0	0

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

The Optimistic Case presents the best that is achievable, given the overriding constraints on financial investment, coal consumption, natural gas consumption, and hydroelectric capacity expansion contained in the Reference Case. While it may be optimistic, it remains a more realistic scenario than that provided by the financially unconstrained Base Case.

In many respects, this scenario represents the outcome of an IRP approach to electric power development, in which all supply-and demand-side options for meeting the demand for electricity services are compared on a least-cost basis. This planning paradigm is finding increasing acceptance among North American electric and gas utilities as an efficient and cost-effective approach to development planning.

As shown in Table 7.13 and 7.14, the optimistic scenario results in a significant improvement in system development relative to the Reference Case. The efficiencies available from DSM, reduced losses, Clean Coal Technologies and Cogeneration enable an additional 47 GW of installed generation capacity to be put in place by 2021, relative to the Reference Case. More important, there is no capacity shortfall until 2016, and the capacity shortfall is reduced to 99 GW, over 126 GW below the Reference Case value in 2021. Total capacity requirements in 2021 reach 465 GW or 6.7 times the 1991 system capacity, *versus* 544 GW for the Reference Case (7.9 times 1991 levels).

Of the generation options made available to the model, 19.5 GW of DSM, 9.6 GW of renewable generation capacity, 37.9 GW of cogeneration, and 76.1 GW of CCT capacity are adopted.

It is noteworthy that, while the entire DSM and renewable capacities are taken up, only 76 GW of CCT/IGCC capacity comes into the system, against a level 134 GW under the Clean Coal Technologies scenario (see Table 7.7) Similarly, only 38 GW of cogeneration capacity comes into the system These results reflect the impact of planning across all available options, rather than focussing on one or a few alternatives to meet power demands. The share of hydro in the total installed capacity under this scenario is 18 8 percent in 2021. Finally, as shown in Table 7.14, all emissions are down over the period relative to the Reference Case.

7.9 Business as Usual with All Options Plus Gas Import

Building on the optimistic scenario discussed above, this scenario assumes that an integrated planning approach to electric power development is put in place, that there are no financial constraints on India's electric power development; and that India is able to import gas from the Middle East to an upper limit of 30 million cubic meters per year.

Table 7.13

Optimistic Scenario--Reference Case with All Options Open

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Installed Generation (MW)								
Coal	45509	43716	59631	86217	133500	184678	207170	4.6
Nuclear	1785	2814	4831	10751	16704	24190	28490	16.0
Natural Gas	2587	4968	19889	20489	20866	22623	23734	9.2
Hydro	19189	23938	33334	42243	49854	59383	69020	3.6
Other	0	0	1900	6272	13294	23405	37925	
Subtotal	69070	75436	119586	165974	234218	314281	366340	5.3
% Hydro	27.8%	31.7%	27.9%	25.5%	21.3%	18.9%	18.8%	
Capacity Shortfall	0	0	0	0	0	17575	98691	
% Gen. Subtotal	0.0%	0.0%	0.0%	0.0%	0.0%	5.6%	26.9%	
Total Capacity Required	69070	75436	119586	165974	234218	331856	465031	6.7
Installed Generation (MW)								
Decentralized Power	0	500	1240	1500	4400	8000	9600	
Demand-side Management	0	2557	4893	7076	11129	14702	19500	
Cogeneration	0	0	1900	6272	13294	23405	37925	
Clean Coal Technologies	0	0	0	6439	23777	53650	76142	
Energy Resource Consumption								
Hydro (MW)	9344	11963	17280	22350	26674	32289	38003	4.1
Coal ('000 tonnes)	129282	146055	208756	282385	406000	516000	650000	5.0
Natural Gas (millions m^3)	3322	4496	12245	12473	12623	14700	14700	4.4
Fuel Oil ('000 m^3)	911	1030	1547	2040	2702	2989	3437	3.8
Nuclear Fuel ('000 kg U)	856	1394	2446	5527	8624	12516	14751	17.2
Environmental Emissions								
Particulates ('000 tonnes)	4136978	4673456	4931076	4639175	4704719	4802940	5164566	1.2
CO_2 ('000 tonnes)	224793	255448	377018	501976	711528	901582	1128233	5.0
SO_2 ('000 tonnes)	1230	1402	2077	2634	3421	3837	4432	3.6
NO_x ('000 tonnes)	1193	1353	1983	2539	3364	3896	4595	3.9
Nuclear Waste ('000 m^3)	9945	16189	28401	64169	100121	145310	171264	17.2

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.14

Optimistic Scenario Minus Reference Case

Year	1991	1996	2001	2006	2011	2016	2021
Installed Generation (MW)							
Coal	0	-11232	-7696	-5284	8079	23369	15741
Nuclear	0	-400	-1300	-1300	-1300	-1300	0
Natural Gas	0	2483	-594	-520	-1161	599	956
Hydro	0	-3230	-1926	-4616	-9561	-10616	-7440
Other	0	0	1900	6272	13294	23405	37925
Subtotal	0	-12378	-9616	-5449	9350	35458	47183
Capacity Shortfall	0	0	-8565	-18305	-45745	-88202	-125892
Total Capacity Required	0	-12378	-18182	-23755	-36394	-52744	-78709
Installed Generation (MW)							
Decentralized Power	0	0	-1960	-3300	-2000	0	0
Demand-side Management	0	2557	4893	7076	11129	14702	19500
Cogeneration	0	0	1900	6272	13294	23405	37925
Clean Coal Technologies	0	0	0	6439	23777	53650	76142
Energy Resource Consumption							
Hydro (MW)	0	-1544	-1125	-2737	-5699	-6331	-4428
Coal ('000 tonnes)	0	-22894	-37268	-37615	0	0	0
Natural Gas (millions m^3)	0	1306	-313	-1243	-2077	0	0
Fuel Oil ('000 m^3)	0	-206	-297	-438	-521	-1153	-1803
Nuclear Fuel ('000 kg U)	-0	7	-676	-676	-675	-676	0
Environmental Emissions							
Particulates ('000 tonnes)	0	300544	-438186	-533856	-50592	-336800	-627241
CO_2 ('000 tonnes)	0	-36171	-63627	-66212	-4316	-464	-395
SO_2 ('000 tonnes)	0	-205	-357	-513	-553	-1182	-1863
NO_x ('000 tonnes)	0	-195	-338	-458	-417	-874	-1383
Nuclear Waste ('000 m^3)	0	85	-7846	-7846	-7846	-7847	0

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

As shown in Tables 7.15 and 7.16, this scenario results in a significant improvement in system development relative to the Base Case. Under this option, an investment of Rs 537,452 crores achieves the virtual elimination of capacity shortfalls. The efficiencies available from DSM, reduced losses, clean coal technologies, and cogeneration, coupled with relaxing the financial constraint on system development, compound to yield a decrease of 58 GW in installed generation capacity in 2021 compared to the Base Case. More important, there is no capacity shortfall until 2021 in this case, and the capacity shortfall is reduced to only 1.6 GW, 23.3 GW below the Base Case value in 2021.

The model picks up the entire natural gas supply (both indigenous and imported) available to the power sector. Natural gas capacity increases almost 32 times its 1991 level by 2021 under this scenario. The relaxation of the coal and financial constraints results in a substantial increase in coal-based installed capacity, from 191 GW in 2021 in the Reference Case to 341 GW under this option. The share of hydro-electric capacity is placed at 10.4 percent. While DSM is seen to reach full potential of 19.5 GW, renewables capacity is only 6.6 GW and cogeneration 22 GW.

The impact on levels of emission is significant. All emissions are lower compared to the Base Case. Particulate emissions are reduced by 1,598 Mt, CO_2 by 461 Mt, SO_2 by 2.7 Mt, and NO_x by 2.6 Mt in 2021 under this scenario relative to the Base Case.

7.10 Scenario Comparisons

With the notable exception of the Optimistic scenario, there is not a clear winner among the development scenarios discussed above. From a policy and planning standpoint, the choice of priorities among the various options will, therefore, depend on the decision criteria used for assessment. This section provides a comparison of scenario results on the basis of three candidate criterion:

- capacity shortfall;
- SO_2, No_x, and CO_2 emissions; and
- total electric power system costs.

7.10.1 Capacity Shortfall

If satisfying demand is an overriding priority in system development, then one important criterion for selection among the various alternative scenarios could be to minimize capacity shortfall. Table 7.17 and Figure 7.2 provide a comparison of capacity shortfalls under the reference and alternative scenarios. All the alternative scenarios result in a reduced capacity shortfall relative to the Reference Case. Under the DSM, Reduced T & D Losses, and Optimistic scenarios, capacity shortfalls are eliminated until the 2006 reporting period. That is, all projected demand for electricity services are

Table 7.15

BAU with All Options Plus Gas Import

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Installed Generation (MW)								
Coal	45509	43716	61084	86404	130067	206114	341336	7.5
Nuclear	1785	2814	4831	4751	4704	4690	4690	2.6
Natural Gas	2587	4968	20438	36781	60603	81181	81890	31.7
Hydro	19189	23938	32952	39146	44210	48695	52290	2.7
Other	0	0	312	793	1449	9979	22229	
Subtotal	69070	75436	119617	167876	241034	350660	502436	7.3
% Hydro	27.8%	31.7%	27.5%	23.3%	18.3%	13.9%	10.4%	
Capacity Shortfall	0	0	0	0	0	0	1611	
% Gen. Subtotal	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%	
Total Capacity Required	69070	75436	119617	167876	241034	350660	504047	7.3
Installed Generation (MW)								
Decentralized Power	0	500	1120	1500	2000	2800	6600	
Demand-side Management	0	2557	4893	7250	11129	14702	19500	
Cogeneration	0	0	312	793	1449	9979	22229	
Clean Coal Technologies	0	0	0	0	0	3763.2	3763.2	
Energy Resource Consumption								
Hydro (MW)	9344	11963	17051	20495	23293	25885	27979	3.0
Coal ('000 tonnes)	129282	146055	208732	299496	448308	693339	1085325	8.4
Natural Gas (millions m^3)	3322	4496	12534	21036	33508	44327	44700	13.5
Fuel Oil ('000 m^3)	911	1030	1555	2304	3532	5491	8740	9.6
Nuclear Fuel ('000 kg U)	856	1394	2446	2407	2385	2378	2130	2.5
Environmental Emissions								
Particulates ('000 tonnes)	4136978	4673456	4788019	5133851	5720476	6458762	7822208	1.9
CO_2 ('000 tonnes)	224793	255448	377593	548118	824770	1260973	1924912	8.6
SO_2 ('000 tonnes)	1230	1402	2080	3029	4569	6928	10657	8.7
NO_x (000 tonnes)	1193	1353	1985	2874	4319	6559	10094	8.5
Nuclear Waste ('000 m^3)	9945	16189	28401	27955	27693	27615	24737	2.5

SOURCES: ELITE, December 1994 Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.16

BAU Plus All Options Minus Base Case

Year	1991	1996	2001	2006	2011	2016	2021
Installed Generation (MW)							
Coal	0	-2762	-20684	-47221	-84174	-128082	-135872
Nuclear	0	0	0	0	0	0	0
Natural Gas	0	-8222	83	15745	38353	-56371	57077
Hydro	0	-2471	-2875	-2030	-2875	-2175	-1669
Other	0	0	312	793	1449	9979	22229
Subtotal	0	-13456	-23164	-32713	-47247	-63907	-58235
Capacity Shortfall	0	0	0	0	0	0	-23266
Total Capacity Required	0	-13456	-23164	-32713	-47247	-63907	-81502
Installed Generation (MW)							
Decentralized Power	0	0	-2080	-3300	-4400	-5200	-3000
Demand-side Management	0	2557	4893	7250	11129	14702	19500
Cogeneration	0	0	312	793	1449	9979	22229
Clean Coal Technologies	0	0	0	0	0	3763.2	3763.2
Energy Resource Consumption							
Hydro (MW)	0	-1489	-1723	-651	1116	6132	1078
Coal ('000 tonnes)	0	-16847	-47519	-95755	-174099	-280994	-308178
Natural Gas (millions m^3)	0	-4322	44	8275	20158	29628	30000
Fuel Oil ('000 m^3)	0	-130	-407	-819	-1459	-2393	-2589
Nuclear Fuel ('000 kg U)	0	0	152	481	760	759	511
Environmental Emissions							
Particulates ('000 tonnes)	0	-270103	116780	286730	-122735	-988308	-1598639
CO_2 ('000 tonnes)	0	-37103	-80337	-145527	-254210	-415884	-460883
SO_2 ('000 tonnes)	0	-203	-451	-827	-1453	-2454	-2710
NO_x ('000 tonnes)	0	-187	-427	-794	-1401	-2345	-2588
Nuclear Waste ('000 m^3)	0	0	1771	5592	8825	8812	5934

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

met under these scenarios. While capacity shortfalls increase rapidly thereafter, under the Reference plus All Options scenario, the shortfall is eliminated until the year 2010 and is only 44 percent of the Reference Case shortfall by 2021.

All scenarios with an investment constraint result in capacity shortfalls ranging from 27-70 percent. While each individual option such as DSM, Cogeneration, etc. indicate shortfalls around 50-60 percent, the combination scenario with investment constraints indicates a substantially reduced shortfall of 27 percent. When the investment constraints are reduced, shortfalls are eliminated. Assuming that funds estimated under the constrained scenario would indeed be made available by the government, the obvious conclusion would be that the additional funds would have to be raised from the private sector, both domestic and foreign, in order to eliminate shortfalls and satisfy all the demand.

7.10.2 Emissions

Limiting CO_2 emissions has gained importance since their identified link to the threat of global warming. While presently, India does not have any commitments for CO_2 and other GHG emissions reductions, the need to study the emissions from different scenarios gains relevance, considering the ten-fold growth of the Indian power sector by 2021 identified in the Reference Case.

Table 7.18 compares CO_2 emissions under the eight scenarios examined, for the reporting periods 1996 through 2021. Under the unconstrained Base Case, CO_2 emissions from the electric power sector exceed 2385 Mt per year by 2021, 8.2 times their estimated 1996 level. Under the Reference Case, CO_2, emissions are estimated at 1128 Mt in 2021, that is roughly 48 percent of Base Case levels. This is largely due to the considerable unsatisfied electricity demand represented by the capacity shortfall of 225 GW in that year, the majority of which is avoided coal-fired generation relative to the Base Case.

The DSM, Reduced T & D Losses, and Optimistic scenarios all yield comparable emissions results, since the level of coal available for power generation is constrained to 650 Mt in all the scenarios. However, the level of capacity shortfall relative to the Reference Case is lower in all these options. The Optimistic scenario, with its comparatively lower CO_2 emissions (see Table 7.18 and Figures 7.3 and 7.4) coupled with a 27 percent capacity shortfall, makes this a preferred option.

Table 7.17a

Scenario Comparisons
Rquired System Capacity Including Capacity Shortfall
('000 MW)

Year	1991	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Base Case	69.1	88.9	142.8	200.6	288.3	414.6	585.5	8.5
Reference Case	69.1	87.8	137.8	189.7	270.6	384.6	543.7	7.9
Demand-side Management	69.1	82.7	126.6	174.6	245.2	347.5	493.2	7.1
Clean Coal Technology	69.1	87.9	137.6	190.1	267.1	380.9	542.6	7.9
Cogeneration	69.1	89.0	139.4	193.4	271.2	386.2	548.2	7.9
Reduced Losses	69.1	84.4	131.0	181.3	254.8	361.1	509.0	7.4
Reference Plus All Options	69.1	75.4	119.6	166.0	234.2	331.9	465.0	6.7
BAU Plus All Options	69.1	75.4	119.6	167.9	241.0	350.7	504.0	7.3

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.17b

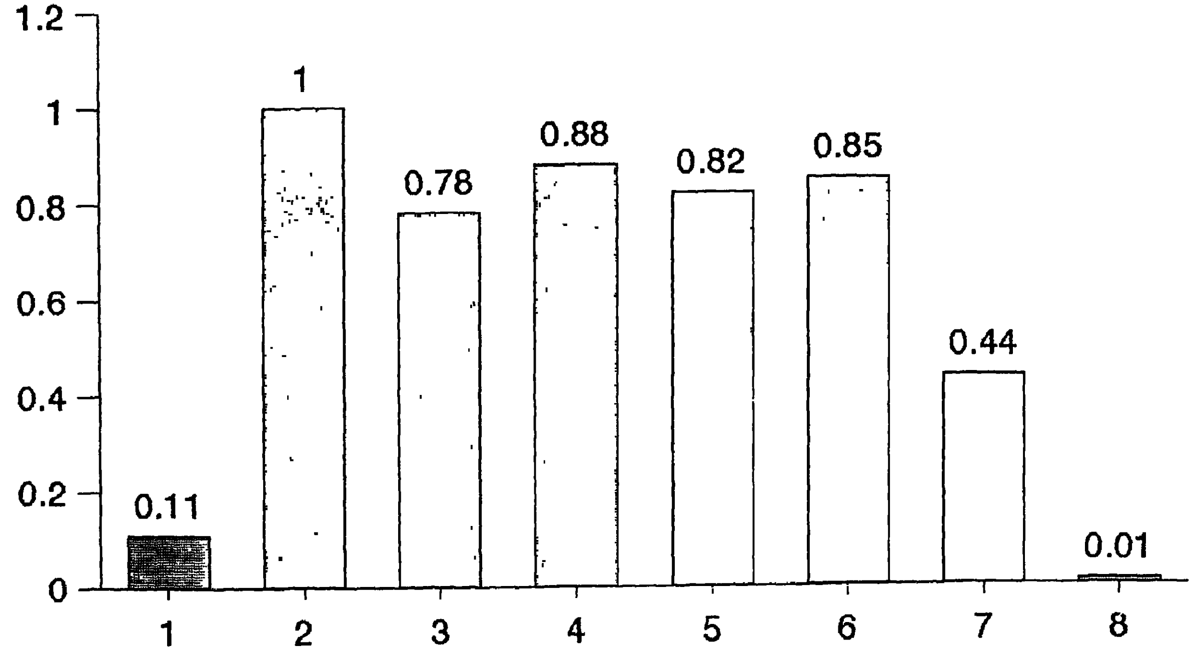
Scenario--Ratio Relative to Reference Scenario

Year	1996	2001	2006	2011	2016	2021
Base Case	101.2	103.6	105.7	106.5	107.8	107.7
Reference Case	100.0	100.0	100.0	100.0	100.0	100.0
Demand-side Management	94.2	91.9	92.0	90.6	90.3	90.7
Clean Coal Technology	100.0	99.9	100.2	98.7	99.0	99.8
Cogeneration	101.3	101.2	101.9	100.2	100.4	100.8
Reduced Losses	96.1	95.1	95.5	94.2	93.9	93.6
Reference Plus All Options	85.9	86.8	87.5	86.6	86.3	85.5
BAU Plus All Options	85.9	86.8	88.5	89.1	91.2	92.7

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Figure 7.2

Capacity Shortfall in 2021
Ratio Relative To Reference Case



1) Base
2) Reference
3) Demand-Side Management
4) Clean Coal
5) Cogeneration
6) Reduced Losses
7) Referen e Plus All Options (IRP)
8) BAU Plus All Options

SOURCE: Canadian Energy Research Institute (January 1995).

Table 7.18a

Scenario Comparisons
Capacity Shortfall
(MW)

Year	2001	2006	2011	2016	2021
Base Case	0	0	0	0	24877
Reference Case	8565	18305	45745	105777	224584
Demand-side Management	0	577	12472	67759	174700
Clean Coal Technology	8567	15961	45291	96317	198686
Cogeneration	7323	13216	35303	84490	185256
Reduced Losses	0	3239	26999	81510	190519
Reference Plus All Options	0	0	0	17575	98691
BAU Plus All Options	0	0	0	0	1611

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.18b

Scenario--Ratio Relative to Reference Scenario

Year	2001	2006	2011	2016	2021
Base Case	0.00	0.00	0.00	0.00	0.11
Reference Case	1.00	1.00	1.00	1.00	1.00
Demand-Side Management	0.00	0.03	0.27	0.64	0.78
Clean Coal Technology	1.00	0.87	0.99	0.91	0.88
Cogeneration	0.85	0.72	0.77	0.80	0.82
Reduced Losses	0.00	0.18	0.59	0.77	0.85
Reference Plus All Options	0.00	0.00	0.00	0.17	0.44
BAU Plus All Options	0.00	0.00	0.00	0.00	0.01

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute

As SO_2, NO_x and particulates are of greater short-term interest to power planners in India than greenhouse gas concerns, Tables 7.19 though 7.21 present these emissions for the eight different scenarios examined. As shown here and in Figures 7.5 to 7.7, the Clean Coal scenario is clearly preferable if SO_2, NO_x and particulate emissions are of primary interest, followed by the Optimistic scenario.

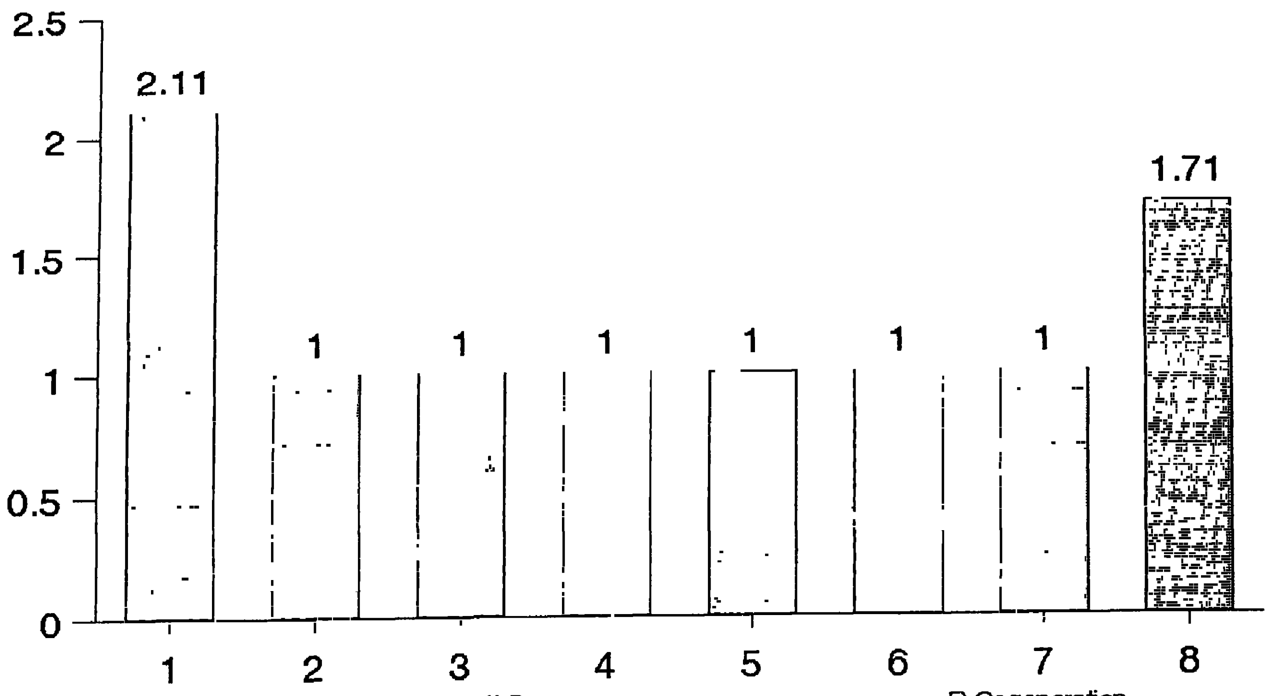
7.10.3 Total System Costs

The total system cost is defined as the cost of total power system development as well as the cost of unsatisfied demand. The India ELGEM model minimizes the total system cost for meeting a specified level of demand (totally or in part) under the given set of constraints. While each scenario introduces a different option into the final solution, it is the integration of these choices available that requires greater attention. The attempt here would be to study all the preferred choices to be evaluated in an integrated framework

As shown in the final two scenarios discussed above, imposing a financial constraint on electric power development and coupling this with recourse to all options in an integrated planning context offers many benefits. Relative to the other scenarios examined here, it offers the best attributes available, if we are concerned with reducing emissions and reducing unsatisfied demand for electricity. As shown in Table 7 22, using all options to satisfy power demand also allows the lowest total installed system cost, whether a financial constraint is imposed or not.

As shown in Table 7.22 and Figure 7 8, the total costs to build and operate the electric power system represented in the BAU Plus all Options Case is 82.5 percent of the unconstrained BAU Case. That is, making good use of DSM, cogeneration, reducing distribution losses, etc., actually results in an 18 percent decrease in total system costs--a significant financial savings of Rs 80,031 crores. In the scenario where realistic financial constraints are imposed on power development, the total system cost is only 86 percent of the unconstrained BAU Plus All Options levels Whether or nor financial constraints are imposed is, therefore, not a central issue--these results indicate that there are large cost and emissions savings that would result from institution of IRP for Indian electric power development (see also Figure 7 9).

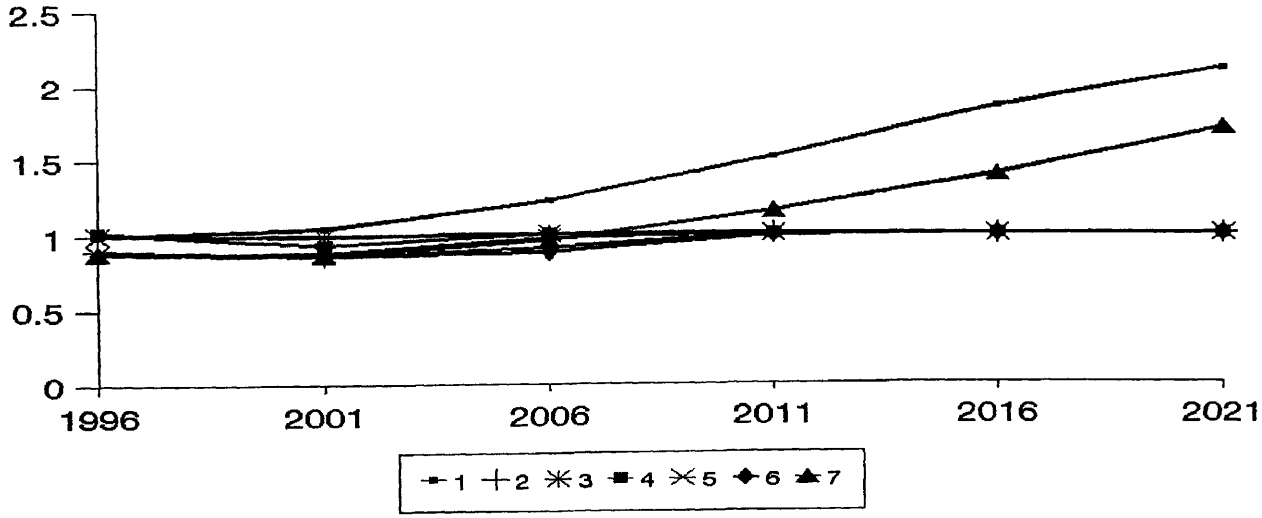
Figure 7.3
CO_2 Emissions in 2021
Ratio Relative to Reference Case



1) Base
2) Reference
3) Demand-Side Management
4) Clean Coal
5) Cogeneration
6) Reduced Losses
7) Reference Plus All Options (IRP)
8) BAU Plus All Options

SOURCE: Canadian Energy Research Institute (January 1995).

Figure 7.4
CO_2 Emissions 1996-2021
Ratio Relative to Reference Case



1) Base
2) Demand-Side Management
3) Clean Coal
4) Cogeneration
5) Reduced Losses
6) Reference Plus All Options (IRP)
7) BAU Plus All Options

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.19a

Scenario Comparisons
Carbon Dioxide Emissions
(million tonnes)

Year	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Base Case	292.6	457.9	693.6	1079.0	1676.9	2385.8	8.2
Reference Case	291.6	440.6	568.2	715.8	902.0	1128.6	3.9
Demand-side Management	263.0	379.4	518.4	715.8	902.0	1128.6	4.3
Clean Coal Technology	291.8	436.9	569.0	715.5	901.2	1127.8	3.9
Cogeneration	296.7	411.3	568.4	715.2	902.0	1128.6	3.8
Reduced Losses	259.1	388.3	550.5	715.8	902.0	1128.6	4.4
Reference Plus All Options	255.4	377.0	502.0	711.5	901.6	1128.2	4.4
BAU Plus All Options	255.4	377.6	548.1	824.8	1261.0	1924.9	7.5

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.19b

Scenario--Ratio Relative to Reference Scenario

Year	1996	2001	2006	2011	2016	2021
Base Case	1.00	1.04	1.22	1.51	1.86	2.11
Reference Case	1.00	1.00	1.00	1.00	1.00	1.00
Demand-side Management	0.90	0.86	0.91	1.00	1.00	1.00
Clean Coal Technology	1.00	0.99	1.00	1.00	1.00	1.00
Cogeneration	1.02	0.93	1.00	1.00	1.00	1.00
Reduced Losses	0.89	0.88	0.97	1.00	1.00	1.00
Reference Plus All Options	0.88	0.86	0.88	0.99	1.00	1.00
BAU Plus All Options	0.88	0.86	0.96	1.15	1.40	1.71

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.20a

Scenario Comparisons
SO_2 Emissions
('000 tonnes)

Year	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Base Case	1605.9	2532.1	3856.9	6023.4	9382.9	13367.9	8.3
Reference Case	1608.0	2435.0	3148.0	3975.0	5020.0	6296.0	3.9
Demand-side Management	1447.0	2090.1	2868.5	3975.3	5020.5	6294.7	4.4
Clean Coal Technology	1573.3	2371.0	2856.9	2926.2	2833.5	2992.5	1.9
Cogeneration	1636.8	2270.0	3149.0	3973.6	5020.6	6298.4	3.8
Reduced Losses	1424.7	2141.2	3049.2	3975.1	5020.5	6294.6	4.4
Reference Plus All Options	1402.8	2077.5	2634.3	3421.9	3837.9	4432.6	3.2
BAU Plus All Options	1402.8	2080.4	3029.4	4569.6	6928.4	10657.4	7.6

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute

Table 7.20b

Scenario--Ratio Relative to Reference Scenario

Year	1996	2001	2006	2011	2016	2021
Base Case	1.00	1.04	1 23	1.52	1.87	2.12
Reference Case	1.00	1.00	1 00	1.00	1.00	1.00
Demand-side Management	0.90	0.86	0 91	1.00	1.00	1.00
Clean Coal Technology	0.98	0.97	0.91	0.74	0.56	0.48
Cogeneration	1 02	0.93	1.00	1.00	1.00	1.00
Reduced Losses	0.89	0.88	0.97	1.00	1.00	1.00
Reference Plus All Options	0.87	0.85	0.84	0.86	0.76	0.70
BAU Plus All Options	0.87	0.85	0.96	1.15	1.38	1.69

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.21a

Scenario Comparisons
NOx Emissions
('000 tonnes)

Year	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Base Case	1541.8	2413.2	3668.6	5721.4	8905.1	12683.4	8.2
Reference Case	1549.0	2322.0	2998.0	3781.0	4771.0	5979.0	3.9
Demand-side Management	1396.9	1995.7	2734.9	3781.2	4771.1	5979.5	4.3
Clean Coal Technology	1524.0	2269.0	2781.0	3005.6	3158.0	3534.6	2.3
Cogeneration	1576.8	2165.0	2998.4	3778.5	4771.3	5979.3	3.8
Reduced Losses	1376.1	2043.1	2905.4	3780.8	4771.1	5979.4	4.3
Reference Plus All Options	1353.9	1983.5	2539.2	3364.0	3896.2	4596.0	3.4
BAU Plus All Options	1353.9	1985.5	2874.5	4319.7	6559.5	10094.7	7.5

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

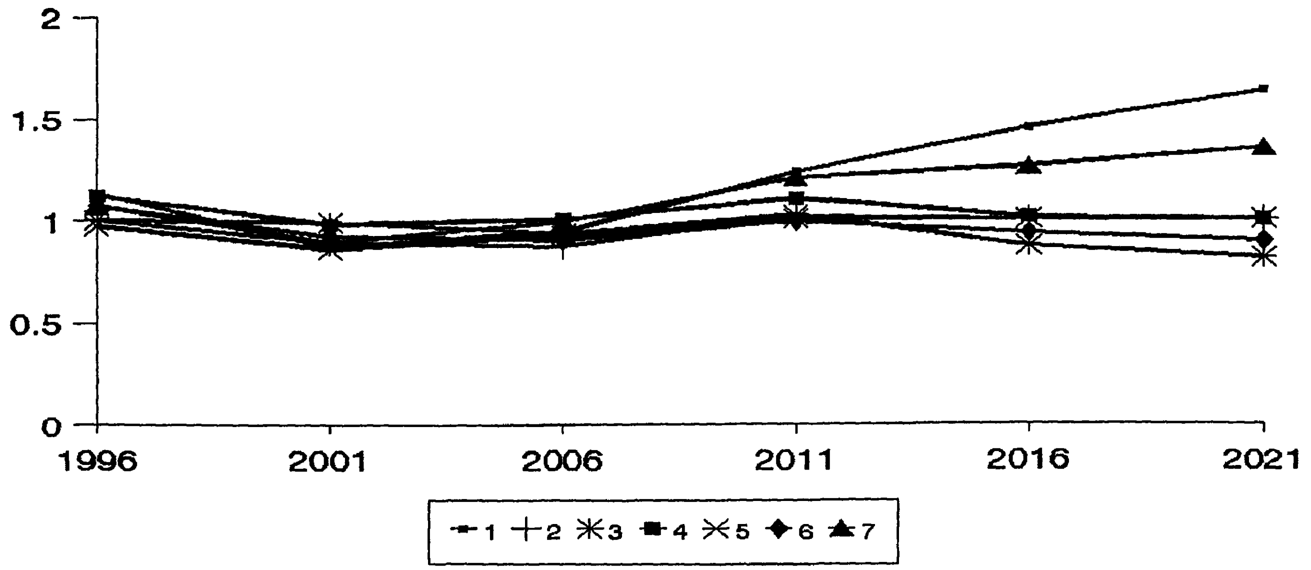
Table 7.21b

Scenario--Ratio Relative to Reference Scenario

Year	1996	2001	2006	2011	2016	2021
Base Case	1.00	1.04	1.22	1.51	1.87	2.12
Reference Case	1.00	1.00	1.00	1.00	1.00	1.00
Demand-side Management	0.90	0.86	0.91	1.00	1.00	1.00
Clean Coal Technology	0.98	0.98	0.93	0.79	0.66	0.59
Cogeneration	1.02	0.93	1.00	1.00	1.00	1.00
Reduced Losses	0.89	0.88	0.97	1.00	1.00	1.00
Reference Plus All Options	0.87	0.85	0.85	0.89	0.82	0.77
BAU Plus All Options	0.87	0.86	0.96	1.14	1.37	1.69

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Figure 7.5
Particulate Emissions 1996-2021
Ratio Relative to Reference Case

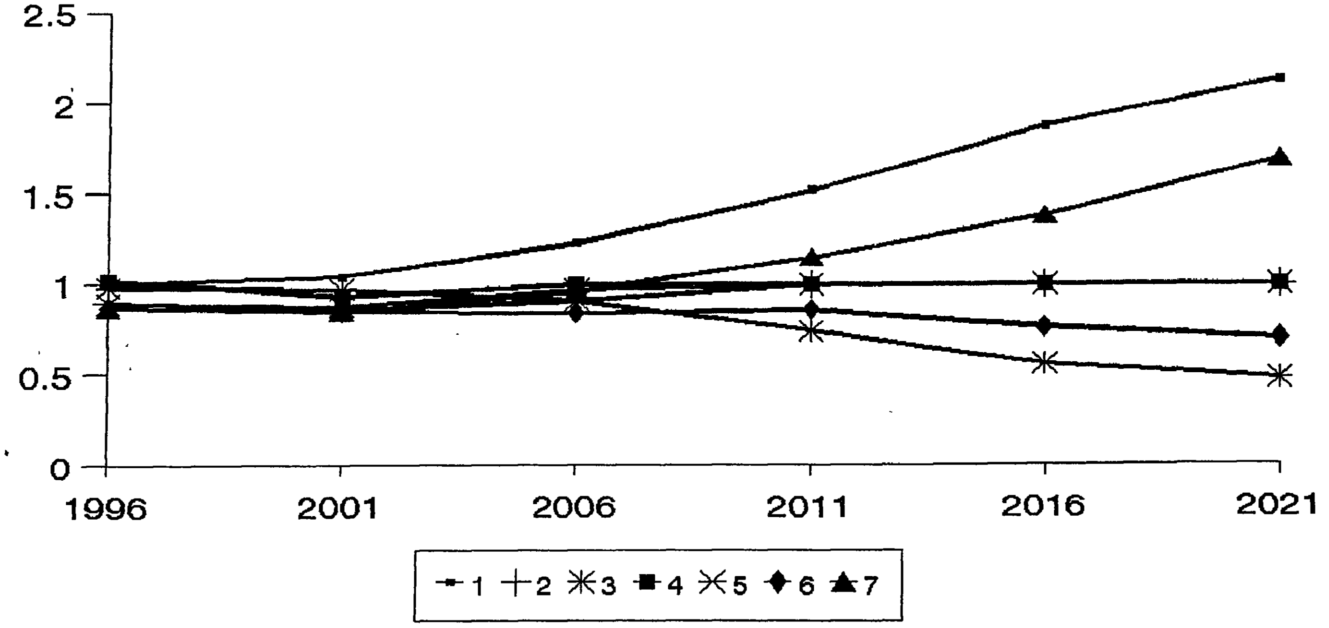


SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

1) Base
2) Demand-Side Management
3) Clean Coal
4) Cogeneration
5) Reduced Losses
6) Reference Plus All Options (IRP)
7) BAU Plus All Options

Figure 7.6

SO_2 Emissions 1996-2021
Ratio Relative to Reference Case

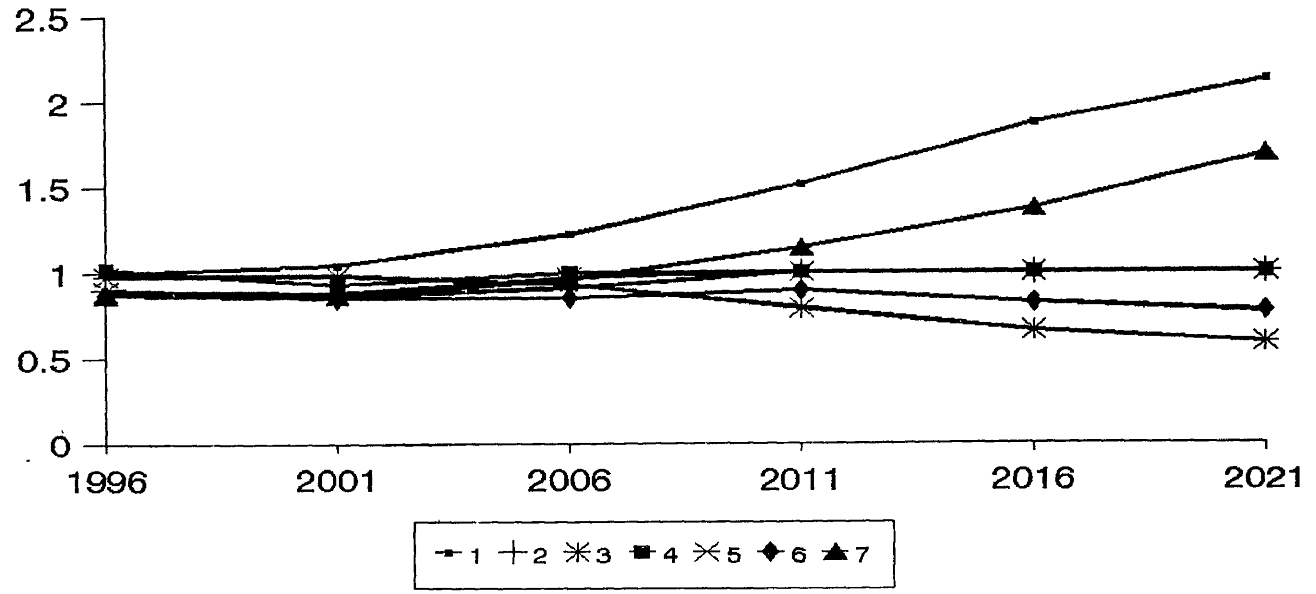


SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

1) Base
2) Demand-Side Management
3) Clean Coal
4) Cogeneration
5) Reduced Losses
6) Reference Plus All Options (IRP)
7) BAU Plus All Options

Figure 7.7

NO_x Emissions 1996-2021
Ratio Relative to Reference Case



1) Base
2) Demand-Side Management
3) Clean Coal
4) Cogeneration
5) Reduced Losses
6) Reference Plus All Options (IRP)
7) BAU Plus All Options

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Table 7.22a

Scenario Comparisons
Particulate Emissions
('000 tonnes)

Year	1996	2001	2006	2011	2016	2021	Ratio 2021/1991
Base Case	4943.6	4671.2	4847.1	5843.2	7447.1	9420.8	1.9
Reference Case	4372.9	5369.3	5173.0	4755.3	5139.7	5791.8	1.3
Demand-side Management	4377.8	4785.9	4482.9	4786.8	5159.8	5814.0	1.3
Clean Coal Technology	4357.9	5340.7	4833.1	4854.9	4462.9	4715.2	1.1
Cogeneration	4896.9	5287.9	5173.2	5208.1	5165.9	5807.0	1.2
Reduced Losses	4257.4	4606.6	4773.9	4766.7	5157.7	5811.7	1.4
Reference Plus All Options	4673.5	4931.1	4639.2	4704.7	4802.9	5164.6	1.1
BAU Plus All Options	4673.5	4788.0	5133.9	5720.5	6458.8	7822.2	1.7

SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

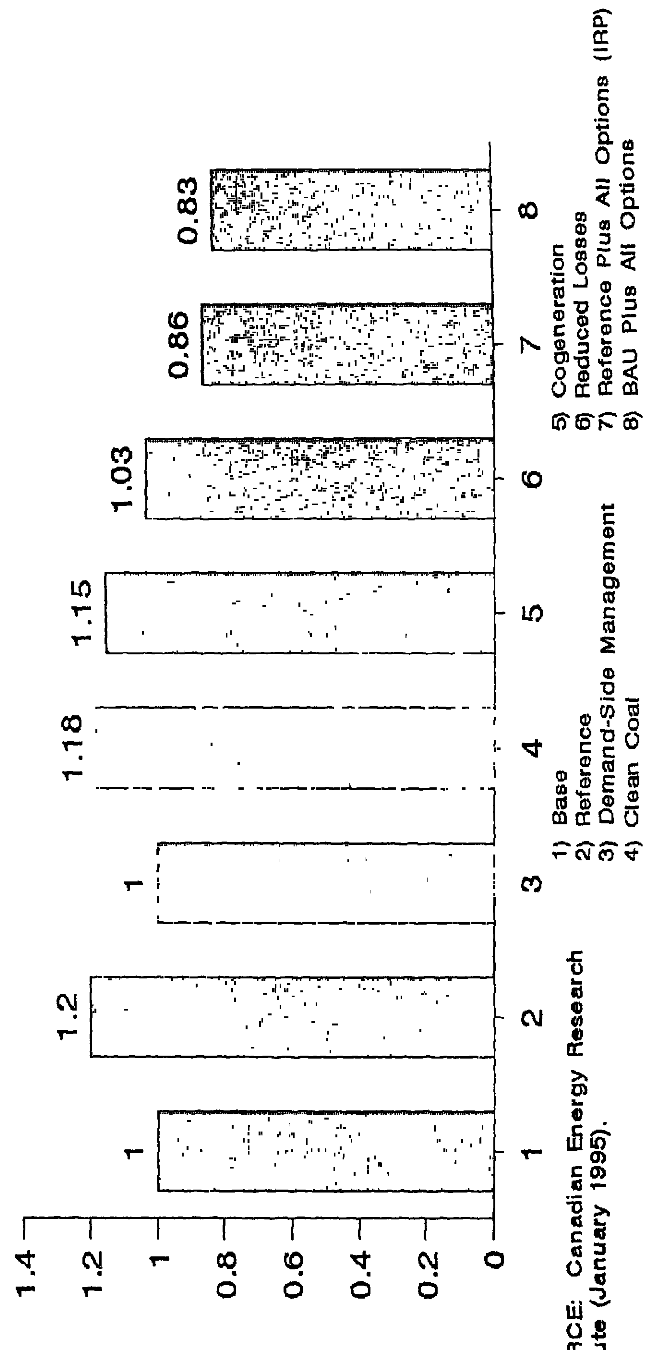
Table 7.22b

Scenario--Ratio Relative to Reference Scenario

Year	1996	2001	2006	2011	2016	2021
Base Case	1.13	0.87	0.94	1.23	1.45	1.63
Reference Case	1.00	1.00	1.00	1.00	1.00	1.00
Demand-side Management	1.00	0.89	0.87	1.01	1.00	1.00
Clean Coal Technology	1.00	0.99	0.93	1.02	0.87	0.81
Cogeneration	1.12	0.98	1.00	1.10	1.01	1.00
Reduced Losses	0.97	0.86	0.92	1.00	1.00	1.00
Reference Plus All Options	1.07	0.92	0.90	0.99	0.93	0.89
BAU Plus All Options	1.07	0.89	0.99	1.20	1.26	1.35

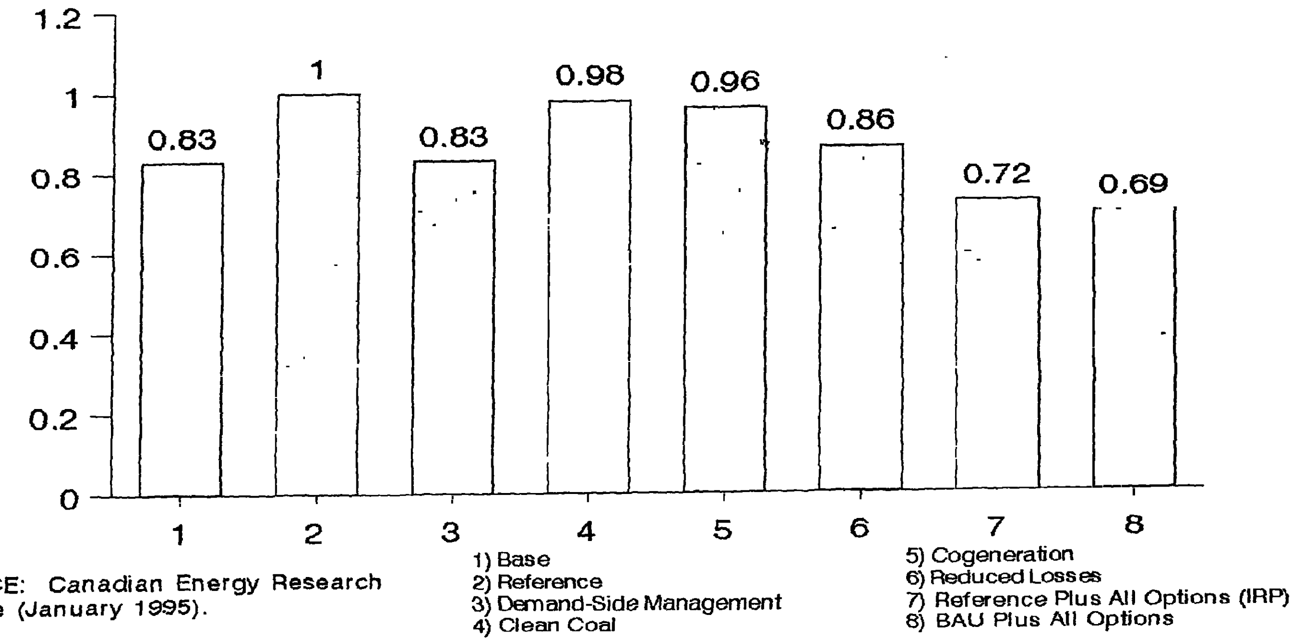
SOURCES: ELITE, December 1994; Canadian Energy Research Institute; Alberta Research Council; and Tata Energy Research Institute.

Figure 7.8
Total System Costs
Ratio Relative to Base Case



SOURCE: Canadian Energy Research Institute (January 1995).

Figure 7.9
Total System Costs
Ratio Relative to Reference Case



SOURCE: Canadian Energy Research *Institute* (January 1995).

7.11 Policy Implications for Indian Power Sector Development

The preferred development strategy is clearly the adoption of IRP and joint implementation of all development option. This is the outcome represented in the Optimistic scenario. Pursuing this development strategy will require considerable change in the structure, operations, regulation, and decision making practices currently governing electric power development in India. Specific policy initiatives required in each of the planning options are discussed below.

7.11.1 Demand-side management

The main impact of the DSM option is on reducing the capacity shortfall and thus postponement of new capacity additions. The success of DSM programs and actual efficiency gains depends on the concerted efforts of the government utilities, manufactures, and electricity consumers themselves, in overcoming the barriers that limit successful implementation of energy efficiency and DSM. The governments have an important catalytic role in promoting energy efficiency through various economic and financial instruments and should formulate policies that would encourage greater end-use efficiency. Possible strategies that would be considered in promoting energy efficiency are:

- develop a national program on energy efficiency;
- SEBs should be encouraged to develop comprehensive DSM plans;
- introduce the concept of IRP;
- design and adopt energy conservation laws and regulations; and
- set efficiency standards for energy consuming equipment.

Perhaps the most important barrier in promoting energy efficiency is the present electricity pricing policies of the SEBs, where electricity is supplied at a rate much lower than the marginal cost of its generation and supply. In fact, for several consumer categories, such as agriculture, domestic, and small industries, tariffs are lower than the average cost of generation and supply. Such tariffs do not provide the right signals to consumers in influencing their consumption behavior. Nor do they generate adequate revenue to maintain the reliability and integrity of the existing power system. The utilities, thus, need to rationalize their tariff policies and also consider various innovative tariff options such as time-of-use tariffs, interruptible rates, etc., to manage the demand for electricity.

Information dissemination is the key to the success of energy efficiency and DSM programs. While there are ongoing efforts ongoing by several organizations, there is a need to consolidate these efforts in order to

ensure that there is maximum outreach. Information dissemination can be achieved through mass media-based awareness campaigns on energy conservation, energy labelling, training of various consumer groups, and developing databases on energy use and efficiency improvements for easy access to the consumers.

The Ministry of Power and the EMC are the nodal organizations responsible for energy efficiency activities in the country. DSM, as a subset of energy efficiency, should be given a major thrust by initiating demonstration projects in selected utilities in the country. Strong networking, preparation of a national program on energy efficiency and DSM with specific targets, and provision of effective support by way of suitable fiscal and financial incentives and/or penalties, are immediately required if the country is to gain from the benefits of energy efficiency.

7.11.2 Clean Coal Technologies

In view of the fact that the Indian power sector will continue to rely heavily on coal-based generation, and the growing concerns towards global warming, India needs to consider various CCT options for coal-based power generation. The technologies should be evaluated both in terms of efficiency and cost considerations, and a long term strategy should be developed for the introduction of these technologies into the Indian market.

Among the various CCTs, IGCC, PFBC and AFBC offer potential for adoption in India in the future, owing to their cost effectiveness, availability, and potential for meeting emission control requirements. The R&D efforts in developing these technologies should be strengthened and demonstration projects should be initiated to evaluate viability and the potential for commercialization of these technologies. A reasonable target would be to introduce CCTs into the Indian Power System by the year 2000.

Another important aspect that needs attention is washing of non-coking coal for power generation. The economic advantages of coal washing in the Indian context are well documented. Washing costs are estimated to be in the range of Rs 100-150 per tonne, which is more than offset by transportation cost savings, even if no credit is taken for availability improvements in the power plant. Coal washing is economically justified whenever transportation distances are greater than about 1000 km.

7.11.3 Cogeneration

Cogeneration potential in energy intensive industries in India such as sugar, textiles, paper, fertilizers, food processing, chemicals and petrochemical is significant. Sugar industries alone offer a cogeneration potential of about 5100 MW out of a total estimated cogeneration potential of 7574 MW in 1993.

Cogeneration of electricity and steam in energy intensive industries offers increased system and fuel efficiency to the industries. It reduces the industries demand for utility power and carries the potential for surplus generation which could be sold to the utilities. Cogeneration thus provides an alternative to conventional utility power and reduces the overall emissions from the power sector. Bagasse-based cogeneration, in particular, being neutral in terms of CO_2 emissions, offers significant environmental benefits.

The potential market for cogeneration in Indian industry will be influenced by energy prices, the economic situation, restructuring tariff regimes, power wheeling and banking facilities, and availability of technology and finances. It is important to have long term purchase contracts between the SEBs and cogenerators for purchase of surplus power to encourage industries to opt for cogeneration. A regulatory framework, such as PURPA (Public Utility Regulatory Policy Act) in which it is mandatory for the public utilities to buy the energy generated by the cogenerator at avoided cost in the U.S. should be examined for possible application to India.

7.11.4 Transmission and Distribution Loss Reduction

The impact of the excessive T & D losses in the Indian power system is two-fold. First, it results in under-utilization of the total energy that is being generated. Second, the energy lost due to excessive T & D losses is required to be compensated for by setting up new generating stations which impose increased financial burden and environmental concern from power generation.

Adequate resources must be provided by the SEBs for strengthening their T & D system and reducing losses. Reduction in technical losses requires transmitting at higher voltages and appropriate HV/LV ratio of transmission lines. Sub-transmission and distribution systems operated by the SEBs are over-stressed due to resource constraints. The distribution systems in the past have been extended from time to time to cater to the immediate load demand rather than on the basis of systematic planning. This has resulted in poor quality of supply, high T & D losses, frequent transformer burnouts etc.. There is thus, an urgent need to strengthen the electricity distribution system by stepping up investment in this sector. The power utilities must formulate comprehensive schemes for development and improvement of sub-transmission and distribution systems by adopting a systematic and methodical approach to planning and design of the distribution system.

In the lower voltage networks, in addition to the augmentation of the network, installation of capacitors, re-conductoring, and eliminating underloading and overloading of distribution transformers, are all required in order to reduce losses. SEBs must undertake system improvement schemes

with the objective to reduce T & D losses and to provide electricity to a greater number of the population with increased reliability and quality.

Curtailment of non-technical losses, which presently accounts for one-third of the total T & D losses, requires a judicious mix of legislative support, increased customer awareness, improved billing and collection procedures, and reliable and high quality meters.

7.11.5 Private Sector Participation in Indian Power Sector

With the resources constraints of the central and state governments, it will be impossible for the government to provide all the resources required for power sector development in future. All the planning options discussed above offer large scope for private sector participation. Even in the Optimistic scenario, installed capacity shortfall of 98.7 GW is estimated in 2021, which will have to be provided by the private sector to bridge the demand for electric power. The GOI has, since 1991, opened the doors to the private sector for participation in power generation but there are several issues that yet remain to be resolved. It is important for the central and the state governments to take appropriate measures to resolve these issues to encourage private sector participation.

Apart from investing in conventional power generation facilities, the private sector has large investment opportunities in India in renewable energy projects such as wind, biomass-based gasifiers, and cogeneration.

The private sector could be involved in the area of DSM--private investors can participate through manufacturing of energy efficient equipment, as well as setting up energy service companies to offer technical and financial assistance in promoting energy efficiency.

7.11.6 State Electricity Boards

The successful adoption of various supply and demand-side planning options for the growth and development of the power sector hinges on the performance and financial viability of the SEBs. The boards must be insulated from interference by the state governments in day-to-day matters and the role of state governments restricted to only advisory, as envisaged in the Electricity (Supply) Act. SEBs must be entrusted with greater autonomy and accountability in their operations. In particular, tariff reform is an area where there is an urgent need to eliminate state government influence and introduce cost-based pricing principles. An autonomous tariff commission/board needs to be set up which would determine electricity prices in a rational and transparent manner. An independent regulatory body is essential for the efficient development of the power sector in the future.

This study has examined a number of options available to the Indian power sector in meeting the country's rapidly growing demand for electricity. Continuation of current practices suggests a future of growing surplus electricity demand and declining electricity system reliability.

There is however, much that can be done to ameliorate these problems, even in the context of financial and energy resource constraints facing the country. Adoption and implementation of integrated resource planning in the power sector, movement toward cost-based pricing principles, and creation (and empowerment) of an independent regulatory authority to oversee the future expansion and operation of the power system are all important steps toward a secure energy future for India.

Appendix A

DESIGNING A COGENERATION SYSTEM: THE TECHNICAL ISSUES

Appendix A

DESIGNING A COGENERATION SYSTEM: THE TECHNICAL ISSUES[1]

A cogeneration facility must be tailored specifically to the plant configuration and production process in question. Because it is generally difficult to match the thermal and electricity demands with the output of the cogeneration facility, the cogeneration system is normally designed to meet the thermal needs (quantity and quality) of the industrial facility. Arrangements are usually made to buy or sell power from the utility.

The technical considerations that determine technology selection include:

Quantity of Thermal Energy Requirements - The quantity of heat is measured as the weight required per unit of time.

Quality of Thermal Energy Requirements - The quality of the heat for industrial purposes is a function of pressure and temperature.

Electrical Energy Requirements - Certain technologies such as combined cycle systems and diesel engines are characterized by relatively high electricity-to-steam ratios, while other systems such as back-pressure steam turbines are geared more towards the production of steam.

Operating Characteristics - The suitability of cogeneration to meet company needs depends on whether the loads are reasonably continuous or whether they vary over time The difficulty in matching the cogeneration system to a facility which has variable steam and power requirements, is that most cogeneration technologies have relatively fixed thermal-to-electrical outputs While these systems can be modified, it is often achieved at the expense of cost and system simplicity.

Reliability - The technology must provide reliable thermal power to maintain production levels

Hook-Up Requirements - If the cogenerator plans to sell electricity back to the utility, they must ensure that their system is synchronized to ensure all phases are matched. It will also require suitable equipment to disconnect the generator before the utility uses its automatic reclosure system, which it does during such natural events as lightning, to ensure reliability and continuity of service.[2]

Fuel Prices and Availability - Because fuel costs may represent about two thirds of annual operating costs, fuel prices and availability are key factors determining the type of cogeneration facility.[3]

Fuel-Use Efficiency - The efficiency of fuel use differs among cogeneration technologies. For instance, combustion turbines have overall system efficiencies between 65 to 75 percent, whereas fuel cells offer efficiencies of greater than 80 percent.

Physical Siting Requirements - The cogeneration equipment will have to correspond to the available space and should be placed in suitable proximity to the production process.

Retrofit *versus* New Facility - Some cogeneration applications involve new plant facilities while others may be retrofitted to existing boiler systems.

Personnel Requirements - Cogeneration systems, due to their added complexity relative to conventional boiler systems, may require additional technical personnel for operation and maintenance.

Emissions - Regulations and restrictions on emissions may affect the cogeneration technology options available.

Regulation - Companies investing in cogeneration facilities may be subject to regulations which cover anything from emissions to project sizing and design.

Endnotes

[1]Anthony E. Reinsch and Ellen F. Battle, *Industrial Cogeneration In Canada: Prospects and Perspectives*, CERI Study No. 24, (Calgary, Alberta: Canadian Energy Research Institute, March 1987) and SFA Pacific, *Future Cogeneration Technologies*, EPRI CU-6795 (Palo Alto, California: Electric Power Research Institute, May 1990).

[2]Joseph P. Zanyk, "Barriers to the Development of Parallel Generation In Canada," in *Cogeneration and Parallel Electric Power Generation: The Opportunities Conference; Proceedings* (Calgary, Alberta: Canadian Energy Research Institute, March 1987).

[3]Nelson E. Hay, ed., *Natural Gas Cogeneration* (Lilburn, GA: The Fairmont Press, 1988).

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Appendix B

TECHNOLOGY MANUFACTURERS IN INDIA

Appendix B

TECHNOLOGY MANUFACTURERS IN INDIA

A brief status report on the technology and availability of some of the components of a cogeneration system in India is given below.

Boilers: The major boiler manufacturers are BHEL, Thermax, Walchandnagar Industries, Texmaco, ISGEC, IBPL, Lipi, ACC - Babcock and others. Most of the major boiler manufacturers have collaborations with leading boiler manufacturers in the world, e.g. Combustion Engineering, Babcock and Wilcox, John Thompson, etc.. Both conventional and fluidized bed combustion (FBC) boilers are being manufactured in India.

Conventional boilers are available as packaged or field erected units in a wide range of capacities and with fuel capability ranging from oil, gas and coal to rice husk and bagasse. Typical examples of large size boilers supplied are 275 tph for coal fired boilers and 130 tph for oil/gas fired boilers. Packaged oil/gas fired boilers of 80 tph are also in use. The large 275 tph boilers (supplied to electric utilities) supply steam at a pressure of 96 kg/cm^2 at a temperature of 530°C. Boilers with steam pressures up to 110 kg/cm^2 at 465°C have also been supplied for industrial applications. Discussion with major manufacturers indicate that they have the capacity to manufacture higher pressure boilers. FBC boilers have been manufactured in a wide range of capacities and are being manufactured to fire a variety of fuels such as high sulphur and high ash coal, rice husk, rice straw and even low grade fuels such as coal washery rejects.

Steam Turbines: There are three manufacturers of steam turbines in India; APE Belliss, Triveni Engineering Works, and BHEL APE Belliss and Triveni manufacture turbines in the lower rating range starting from a few hundred kilowatts to 5-6 MW. BHEL manufactures steam turbines in a wider range of capacities from 1 MW to 500 MW (for thermal power plants). These turbines are available in different configurations, i.e. simple back pressure, condensing, extraction condensing, and multiple extraction turbines.

In the lower range of capacity (up to 5 MW) steam turbines are being manufactured to operate at pressures of 30 to 45 kg/cm^2. Most of these turbines are supplied to the sugar industry, and conform to specifications as laid down by the National Federation of Co-operative Sugar Factories Limited. Manufacturers of these turbines claim to have the capability to manufacture turbines rated higher than 65 kg/cm^2 with maximum extraction at about 22 kg/cm^2 for the extraction steam turbines.

BHEL manufactures steam turbines operating at pressures up to 100 kg/cm^2 and has the capacity to manufacture machines at higher pressures. Turbines with back pressure of over 22 kg/cm^2 have been supplied. BHEL also offers multiple

extraction steam turbines with extraction at pressures higher than 22 kg/cm^2.

Single-stage back pressure turbines typically operate at an efficiency of 30-40 percent. For multistage back pressure turbines, the efficiency is in the range of 40-50 percent. For condensing turbines, typical efficiencies are in the range of 60-70 percent.

Gas Turbines: In India, gas turbines are available from BHEL, Triveni Engineering Works, DLF Energy Systems, and Kirloskar Oil Engines. While BHEL and Triveni supply heavy duty industrial gas turbines (typically in the range of 4.5 to 38 MW), DLF Energy Systems supply aero-derivative gas turbines (1-5 MW range). BHEL is the only manufacturer of gas turbines in the country and these machines are made in collaboration with General Electric. Triveni and DLF Energy Systems supply Ruston and Allison-GM machines respectively. Typically, gas turbines operate at an efficiency of 22-26 percent (typical Indian operating conditions) in the lower ratings up to 5 MW.

Diesel Engines: There are various manufacturers of diesel engines in the country manufacturing both high speed and medium speed engines. Low speed and medium speed engines are more suitable for cogeneration application. The major manufacturers in India are Kirloskar Pielstick, Garden Reach, K.G. Khosla and Wartsila. The new medium speed engines proposed to be manufactured in the country will be able to use heavy fuel oils of up to 700 centistoke (at 50°C). These engines in the range of 4-6 MW would typically operate at an efficiency of 38-43 percent. In India, there are only a few installations of diesel engine based cogeneration systems with total capacity approaching 52 MW.

Waste Heat Boilers: The main manufacturers of waste heat boilers in the country are BHEL, Thermax, Cethar Vessels, ISGEC John Thompson, Texmaco, L&T, and Kaveri Engineering. Waste heat boilers of ratings up to 62 tph with single pressure and 105 tph with dual pressure are being manufactured in the country. Among smaller units, used for operation in a cogeneration system, is a 38 tph waste heat boiler used to produce steam at a pressure of 15 kg/cm^2 and 256°C temperature. Installed in a refinery, it uses refinery gas as the heat source. However, most of these waste heat boilers have been supplied to fertilizer and chemical industries and refineries using process gas, natural gas and residual oil as the fuel.

The capability to manufacture fired waste heat boilers also exists in the country. The largest fired waste heat boiler supplied is a dual pressure boiler supplying saturated steam at 39 kg/cm^2 and 10 kg/cm^2.

Appendix C

ASSUMPTIONS FOR ESTIMATING REALIZABLE ELECTRICITY SAVINGS POTENTIAL IN INDIA

Appendix C

ASSUMPTIONS FOR ESTIMATING REALIZABLE ELECTRICITY SAVINGS POTENTIAL IN INDIA

Domestic Sector

1. Replace GLS with CFL and FLT

    - Hours of usage: 4 hrs/day, i.e. 1460 hours per year
    - 60 Watt GLS replaced by 20 Watt (+14 Watt for choke) FTL
    - 60 Watt GLS replaced by 11 Watt (+5 Watt for choke) CFL
    - Market Penetration Rate (MPR)

Old light points:	1 percent changed to CFLs every year
	10 percent changed to FTLs every year
New light points:	1 percent changed to CFLs every year
	20 percent changed to FTLs every year

2. Replace FTL with 'slimlines'

    - 40 Watt (+14 Watt for choke) FTL replaced by 36 Watt (+14 Watt) 'slimline'
    - Market Penetration Rate (MPR)

Old light points:	20 percent changed to slimlines every year
New light points:	All 'slimlines'

3. Ordinary refrigerators

    - average 165 liter ordinary refrigerator consumes 540 kWh/year
    - 10 percent savings are assumed through improved use practices
    - no ordinary refrigerators available in the market after 2007/08

4. Moderate efficiency refrigerators

    - moderate efficiency improvement through (i) increasing thickness of insulation (ii) use of high efficiency compressors (iii) increased evaporator surface area and (iv) tighter door seals

    - moderate efficiency refrigerators consume 420 kWh/year

    - MPR: 25 percent of total refrigerator sales in 1991 were of moderate efficiency refrigerators, which is assumed to increase to 75 percent in 2011/12

5. High efficiency, CFC free refrigerators

    - 165 liter refrigerator will consume 300 kWh/year
    - MPR: 10 percent of the refrigerator sales in 2000/01 assumed to be of high efficiency CFC free refrigerator and this is further assumed to increase to 25 percent by 2011/12

6. Efficiency improvement in fans

    - 10 percent savings through use of efficient motors in fans
    - MPR: all new fans will have efficient motors

7. Air-conditioners

- Average 1 ton air-conditioner consumes 2 kW
- EER can be increased from 8.4 at present to 9, i.e. 16 percent savings can be achieved
- MPR: All new A.C. assumed to be energy efficient

8. Evaporative coolers

- Existing stock of evaporative coolers to decline to zero by 1989/99
- 20 percent savings assumed

B. Commercial sector

1. Replace GLS with CFL and FLT

- Hours of usage: 6 hrs/day,
- 60 Watt GLS replaced by 20 Watt (+14 Watt for choke) FTL
- 60 Watt GLS replaced by 11 Watt (+5 Watt for choke) CFL
- Market Penetration Rate (MPR)

Old light points:	2 percent changed to CFLs every year
	10 percent changed to FTLs every year
New light points:	5 percent changed to CFLs every year
	25 percent changed to FTLs every year

2. Replace FTL with 'slimlines'

- 40 Watt (+14 Watt for choke) FTL replaced by 36 Watt (+14 Watt) 'slimline'
- Market Penetration Rate (MPR)

Old light points:	50 percent changed to 'slimline' every year
New light points:	All use 'slimlines'

3. Replace HPMV with HPSV

- 250 Watt HPMV replaced by 150 Watt HPSV
- Existing HPMV points replaced at the rate of 25 percent every year in 85 percent applications, i.e. in 4 years 855 of the existing HPMV points will be replaced with HPSV
- MPR: 85 percent of application in any year can switch over to HPSV

4. Improved HVAC system

- 25 percent savings can be achieved through use of roof insulation, use of window coatings, use of light colored paints, increasing natural ventilation and daylight etc.
- In 2011/12, 70 percent of the stock will be new HVAC system

Table C.1

Sectoral Electricity Demand Under DSM Scenario

Year	Agriculture	Domestic	Commercial	Industry	Railways	Others	Total
1992/93	52 563	43 015	12 588	90 971	4 796	9 968	213 902
1993/94	55 108	49 254	14 015	97 434	5 121	11 235	232 167
1994/95	57 869	56 483	15 676	104 397	5 467	12 627	252 519
1995/96	60 765	64 806	17 572	111 860	5 833	14 168	275 033
1996/97	63 895	74 333	19 716	119 823	6 219	15 876	299 862
1997/98	67 222	85 376	22 138	128 287	6 623	17 776	327 422
1998/99	70 806	97 513	24 873	137 254	7 048	19 896	357 390
1999/2000	74 608	111 455	27 965	146 725	7 493	22 274	390 520
2000/01	78 740	127 448	31 458	156 704	7 957	24 946	427 253
2001/02	83 117	144 696	35 443	167 192	8 442	27 967	466 857
2002/03	83 529	160 474	37 857	178 192	8 947	29 820	498 819
2003/04	84 019	177 610	40 440	189 709	9 470	31 845	533 094
2004/05	84 600	196 187	43 202	201 747	10 015	33 947	569 698
2005/06	85 284	216 287	46 149	214 310	10 578	36 249	608 858
2006/07	86 087	238 006	49 288	227 402	11 161	38 726	650 670
2007/08	86 748	262 619	52 639	241 731	11 807	41 424	696 969
2008/09	87 418	289 832	56 193	256 974	12 496	44 347	747 259
2009/10	88 096	319 908	59 941	273 188	13 229	47 515	801 877
2010/11	88 783	353 146	63 866	290 432	14 011	50 953	861 192
2011/12	89 479	389 873	67 939	308 772	14 844	54 687	925 594

SOURCE: Tata Energy Research Institute.

C. Agriculture sector

1. Retrofitting of old pumpsets, changing only foot valves and replacing return and supply pipes

   - Savings of 25 percent assumed
   - MPR: 1 percent existing pumpsets are retrofitted every year

2. Energy efficient pumpsets

   - Savings 20 percent
   - MPR: all new pumpsets installed are energy efficient pumpsets

Appendix D

STATISTICAL ELECTRICITY DATA FOR INDIA

Table D.1

Installed Capacity by Region
As of March 31
(percent)

	1971	1977	1980	1984	1987	1988	1989	1992
N. Region[a]								
Hydro	61.37	47.90	47.99	42.68	38.79	36.59	34.14	30.74
Steam Thermal	34.83	45.91	48.36	52.85	56.32	59.24	59.06	56.98
Diesel and Wind	3.40	1.89	0.83	0.54	0.36	0.13	0.12	0.10
Gas	0.40	0.40	0.15	0.00	1.34	1.17	2.82	7.78
Nuclear	0.00	3.90	2.68	3.94	3.27	2.87	3.86	4.40
Total (MW)	**3 152.55**	**5 634.28**	**8 224.02**	**11 179.78**	**13 462.44**	**15 344.92**	**17 470.97**	**20 335.44**
W. Region[b]								
Hydro	28.12	29.75	22.93	15.12	14.19	13.22	12.51	12.81
Steam Thermal	59.09	61.71	70.96	78.90	77.96	79.83	81.03	80.35
Diesel and Wind	1.02	0.08	0.04	0.02	0.02	0.03	0.02	0.16
Gas	1.34	0.96	0.69	2.46	4.95	4.39	4.07	4.70
Nuclear	10.44	7.49	5.38	3.51	2.86	2.54	2.36	1.98
Total (MW)	**4 023.83**	**5 607.05**	**7 808.52**	**11 975.00**	**14 680.63**	**16 533.31**	**17 818.31**	**21 242.14**
S. Region[c]								
Hydro	70.40	66.72	63.73	63.13	59.99	59.03	54.49	48.14
Steam Thermal	29.04	32.88	35.97	33.60	36.21	37.37	42.24	48.38
Diesel and Wind	0.07	0.05	0.02	0.02	0.03	0.04	0.05	0.12
Gas	0.50	0.35	0.28	0.21	0.00	0.00	0.00	0.63
Nuclear	0.00	0.00	0.00	2.50	3.76	3.55	3.23	2.73
Total (MW)	**4 034.71**	**5 634.22**	**7 207.31**	**9 397.81**	**12 488.55**	**13 224.84**	**14 567.19**	**17 222.79**

(Continued On Next Page)

Table D.1 (Continued)

	1971	1977	1980	1984	1987	1988	1989	1992
E. Region[d]								
Hydro	12.39	18.95	18.63	16.13	13.96	15.37	15.23	16.30
Steam Thermal	86.56	80.16	16.81	81.44	84.15	82.78	81.82	81.06
Diesel and Wind	1.06	0.89	0.86	0.78	0.61	0.61	0.61	0.58
Gas	0.00	0.00	2.05	1.65	1.29	1.24	2.33	2.06
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total (MW)	3 305.47	4 327.52	4 866.74	6076.88	7 741.42	8 068.28	8 161.21	9 211.93
N.E. Region[e]								
Hydro	34.99	29.67	43.13	43.81	35.62	42.53	41.23	40.68
Steam Thermal	0.00	24.48	18.32	26.08	36.63	33.24	34.93	31.82
Diesel and Wind	22.65	15.16	14.67	9.32	8.43	6.70	6.96	6.89
Gas	42.36	30.69	23.88	20.79	19.32	17.53	16.88	20.61
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total (MW)	192.39	265.52	341.24	709.39	892.82	963.82	1 022.00	1 052.89
All India (MW)	14 708.95	21 468.59	28 447.83	39338.86	49 265.86	54 155.17	59 039.68	69 065.19

[a]Includes Haryana, Himachal Pradesh, Jammu & Kashmir, Punjab, Rajasthan, Uttar Pradesh, Chandigarh and Delhi.
[b]Includes Gajarat, Madhya Pradesh, Maharashtra, Goa, Daman-Diu, Dadra and Nagar Haveli.
[c]Includes Andhra Pradesh, Karnataka, Kerala, Tamil Nadu, Pondicherry and Lakshadweep.
[d]Includes Bihar, Orissa, West Bengal, DVC, Andaman and Nicobar Islands and Sikkim.
[e]Includes Assam, Manipur, Meghalaya, Tripura, Arunachal Pradesh, Mizoram and Nagaland.

SOURCES: (1) Central Electricity Authority, *Public Electricity Supply*. All India Statistics General Review, various issues; and (2) Central Electricity Authority, *Power Supply Position in the Country*, Vol. 17, No. 5, New Delhi, May 1989.

Table D.2

Thermal Power Stations By Capacity Groups
(MW)

Capacity Group	Commissioned up to March 31, 1991	
	Number	Capacity (MW)
500	13	6500
200/210	101	21090
140/150	9	1270
115/120	20	2380
105/110	39	4245
90/100	11	1042
70/80	9	680
62.5/67.5	22	1375
60	25	1485
40/55	29	1275
20/32	33	840
Total	311	42182

SOURCE: Performance review of thermal power stations, 1990/91, Central Electricity Authority.

Table D.3

Annual Gross Generation by Region
(GWh)

	1970/71	1976/77	1979/80	1982/83	1985/86	1986/87	1987/88	1988/89	1991/92
N. Region[a]	**11 863**	**23 858**	**29 227**	**37 077**	**46 134**	**53 147**	**59 994**	**66 674**	**89 304**
Hydro	55.77	48.05	52.95	49.99	42.66	41.44	34.78	35.35	30.47
Steam	43.93	47.31	43.15	48.52	54.55	55.79	62.15	61.44	59.85
Diesel	0.30	0.04	0.02	0.01	0.00	0.00	0.00	0.00	0.00
Gas	0.00	0 01	0.01	0.00	0.00	0.28	0.75	0.41	7.83
Nuclear	0.00	4.59	3.87	1.49	2.80	2.49	2.32	2.80	1.85
W. Region[b]	**16 912**	**25 981**	**32 077**	**40 188**	**57 376**	**62 733**	**68 471**	**72 833**	**94 196**
Hydro	32.39	29.45	24.77	16.30	10.36	9.81	7.40	10.35	8.66
Steam	52.89	61.85	69.55	77.19	84.26	82.89	86.51	84.40	85.79
Diesel	0.09	0.00	0.00	0.00	0.00	0.00	0.00[c]	0.00[c]	0.02
Gas	0.34	0.040	0 24	2.85	1.97	4.11	3.74	2.64	3.72
Nuclear	14.29	8.30	5.44	3.66	3.42	3.19	2.34	2.61	1.81
S. Region[d]	**15 710**	**21 714**	**27 032**	**33 682**	**43 496**	**46 875**	**47 457**	**54 213**	**72 176**
Hydro	74.34	60.22	71.60	60.11	49.11	44.96	36.57	39.91	41.05
Steam	25.65	39.77	28.40	39.88	46.91	51.40	59.13	56.29	55.41
Diesel	0.00	0.00	0.00	0.01	0.00	0.02	0.02	0.02	0.05
Gas	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.50
Nuclear	0.00	0.00	0.00	0.00	3.98	3.62	4.29	3.78	2.99

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Table D 3 (Continued)

	1970/71	1976/77	1979/80	1982/83	1985/86	1986/87	1987/88	1988/89	1991/92
E. Region[e]	**10 959**	**15 977**	**15 393**	**17 922**	**21 167**	**22 982**	**23 958**	**25 159**	**28 270**
Hydro	12.01	15.37	15.16	14.30	13.98	15.97	13.33	14.96	20.78
Steam	87.70	84.55	83.99	84.41	85.78	83.76	86.43	84.66	78.77
Diesel	0.29	0.07	0.18	0.11	0.00	0.10	0.13	0.13	0.19
Gas	0.00	0.00	0.66	1.18	0.23	0.17	0.12	0.25	0.26
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
N.E. Region[f]	**385**	**803**	**898**	**1 395**	**1 837**	**1 980**	**2 214**	**2 516**	**3 083**
Hydro	41.96	39.97	40.87	34.42	49.20	47.21	43.77	54.13	61.37
Steam	15.45	18.65	21.65	28.83	22.20	22.35	23.57	25.57	20.59
Diesel	3.54	2.89	2.08	1.39	1.10	1.23	1.35	1.19	1.00
Gas	39.05	38.49	35.40	35.36	27.49	29.21	31.31	19.11	17.04
Nuclear	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
All India	**55829**	**88333**	**104627**	**130264**	**170010**	**187717**	**202094**	**221395**	**287 029**

[a]Includes Haryana, Himachal Pradesh, Jammu & Kashmir, Punjab, Rajasthan, Uttar Pradesh, Chandigarh and Delhi.

[b]Includes Gajarat, Madhya Pradesh, Maharashtra, Goa. Daman-Diu, Dadra and Nagar Haveli.

[c]Includes 1.56 GWh from Windmill. Neg < 0.5 Gwh.

[d]Includes Andhra Pradesh, Karnataka, Kerala, Tamil Nadu, Pondicherry and Lakshadweep.

[e]Includes Bihar, Orissa, West Bengal, DVC, Andaman and Nicobar Islands, Sikkim, Andhra Pradesh, Karnataka, Kerala, Tamil Nadu, Pondicherry and Lakshadweep.

[f]Includes Assam, Manipur, Meghalaya, Tripura, Arunachal Pradesh, Mizoram and Nagaland.

SOURCE: Central Electricity Authority, *Public Electricity Supply*. All India Statistics General Review, various issues.

Table D.4

Length of Transmission and Distribution Lines by Region
(ckt. km)

Region	Total	HVDC	400 KV	220 KV 132 KV 110 KV	66 KV 33 KV 22 KV	11 KV 6.6 KV 3.3 KV	0.4 KV
As on March 31, 1981							
Northern[a]	732 604		1 427	24 984	50 050	272 446	383 697
Western[b]	656 114		913	28 619	63 251	199 828	363 504
Southern[c]	847 199			23 467	47 538	193 951	583 343
Eastern[d]	247 908			12 665	21 842	104 999	108 402
Northeastern[e]	38 635			1 837	7 953	13 289	15 556
Total	2 522 461		2 340	91 572	190 634	784 513	1 453 402
As on March 31, 1989							
Northern[a]	1 143 696		3 774	37 347	62 290	409 313	630 972
Western[b]	1 224 011		5 032	41 410	81 213	379 425	716 931
Southern[c]	1 518 949		982	41 397	35 333	326 802	1 114 435
Eastern[d]	422 382		572	21 754	28 008	166 496	205 552
Northeastern[e]	98 409		0	54 301	9 093	42 665	41 221
Total	4 407 447		10 360	147 338	215 937	1 324 701	2 709 111

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Table D.4 (Continued)

Region	Total	HVDC	400 KV	220 KV 132 KV 110 KV	66 KV 33 KV 22 KV	11 KV 6.6 KV 3.3 KV	0.4 KV
As on March 31, 1992							
Northern[a]	1 211 439	1 630	6 534	41 024	63 994	429 242	669 015
Western[b]	1 317 883		10 320	44 081	85 000	412 254	766 228
Southern[c]	1 505 547		4 399	41 625	66 275	328 361	1 064 887
Eastern[d]	435 959		1 832	22 732	28 822	170 544	212 029
Northeastern[e]	103 372		0	6 014	9 691	44 712	42 955
Total	4 574 200	1 630	23 085	155 476	253 782	1 385 113	2 755 114

NOTE: 'ckt.km' represents circuit kilometres.

[a]Includes Haryana, Himachal Pradesh, Jammu & Kashmir, Punjab, Rajasthan, Uttar Pradesh, Chandigarh and Delhi.
[b]Includes Gajarat, Madhya Pradesh, Maharashtra, Goa, Daman-Diu, Dadra and Nagar Haveli.
[c]Includes Andhra Pradesh, Karnataka, Kerala, Tamil Nadu, Pondicherry and Lakshadweep.
[d]Includes Bihar, Orissa, West Bengal, DVC, Andaman and Nicobar Islands and Sikkim.
[e]Includes Assam, Manipur, Meghalaya, Tripura, Arunachal Pradesh, Mizoram and Nagaland.

SOURCE: Public Electricity Supply, All-India statistics, CEA, various issues.

Table D.5

Progress of Rural Electrification

	Village Electrified ('000)		
	No. of Villages	% of Total	Pumpsets Energised ('000)
1950/51	3	0.5	21
1960/61	22	3.8	199
1968/69	74	12.8	1089
1973/74	157	27.2	2426
1977/78	217	37.6	3300
1978/79	233	40.4	3599
1979/80	250	43.4	3966
1984/85	370	64.3	5709
1989/90	470	81.3	8308
1990/91	482	83.7	8972
1991/92	487	84.1	9391

SOURCE: Public Electricity Supply, All India Statistics, General Review, Various issues, Central Electricity Authority, New Delhi.

Table D.6

Performance of Thermal Power Stations in Various Capacity Groups

Capacity	Commissioned upto 31-03-91 No.	Commissioned upto 31-03-91 Capacity (MW)	Reviewed During 1990-91 No.	Reviewed During 1990-91 Capacity (MW)	Plant Load Factor (percent) 1988/89	Plant Load Factor (percent) 1989/90	Plant Load Factor (percent) 1990/91
500	13	6 500	11	5 500	74.97	70.03	61.02
200/210	101	21 090	90	18 780	60.65	61.71	60.24
140/150	9	1 270	9	1 270	42.74	49.24	40.94
115/120	20	2 380	20	2 380	38.73	41.62	41.87
105/110	39	4 245	37	4 025	47.20	45.92	37.98
90/100	11	1 042	11	1 042	52.53	53.38	57.61
70/80	9	680	8	610	32.96	35.66	27.34
62.5/67.5	22	1 375	22	1 375	51.22	54.23	51.78
60	25	1 485	25	1 485	47.86	45.78	44.57
40/55	29	1 275	28	1 225	49.36	51.12	51.29
20/32	33	840	23	606	41.84	36.18	36.66
Total	311	42 182	284	38 298	54.93	56.22	53.89

SOURCE: Central Electricity Authority, 1990/91.

Table D.7

Details of Coal Quality and Specific Coal Consumption at Various Thermal Power Stations in 1990-91

Range of Calorific Value of Coal (Kcal/kg)	Name of Stations with Specific Coal Consumption (Kg/kWh)		
Above 5000	Fandabad (0.80)	Bandel (0.59)	H'Ganj A (1.00)
	Kanpur RPH (2.80)	Tanda (0.85)	K'Kheda (1.16)
	Santaldih (0.66)	D.P.L. (0.76)	AE Co. (0.58)
	CESC (0.97)	Kolaghat (0.64)	
4500-4999	I.P. (0.69)	R Gundem B (0.70)	H Ganj B&C (0.99)
	Unchahar (0.75)	Panki (0.78)	Pancha (0.80)
	Singrauli (0.57)	Wankbori (0.64)	Sikka Repl. (0.64)
	Nasik (0.73)	Gandhi Ngr (0.60)	Bokaro (0.86)
	Durgapur (0.74)	Vindhyachal (0.67)	Titagarh (0.61)
4000-4499	Panipat (0.83)	K Gudem (0.88)	Vijayawada (0.71)
	Bhatinda (0.72)	Rihand (0.56)	Ukai (0.55)
	Amarkantak (0.80)	Bhusawal (0.72)	Chandrapur (0.84)
	Paras (0.80)	Parli (0.75)	R Gundem STPS (0.62)
	Patratu (0.82)	Barauni (0.95)	Muzaffarpur (0.90)
	Bongaigaon (0.60)	Chandrapura (0.75)	
3500-3999	Badarpur (0.84)	Obra (0.77)	Korba E (0.95)
	Ropar (0.66)	Korba STPS (0.70)	Koradi (0.77)
	Kota (0.64)	Trombay (0.60)	Tuticonn (0.63)
	Anpara (0.84)	Talcher (0.87)	
Below 3500	Korba West (0.70)	Ennore (0.92)	Mettur (0.77)
	Raichur (0.75)	Satpura (0.82)	Farakka (0.86)

SOURCE: Central Electricity Authority, 1990/91.

Table D.8

Financial Performance of the SEBs
(in terms of rate of return)

Year	No. of SEBs who have achieved the target rate of return of 3 percent	No. of SEBs who have achieved the surplus but less than 3 percent	No. of SEBs with negative rate of return	Rate of return (all SEBs)
1985/86	0	1	17	-10 5
1986/87	0	2	16	-10.2
1987/88	0	2	16	-12.3
1988/89	1	0	18	-12.8
1989/90	1	0	18	-13.8
1990/91	2	0	16	-13.9
1991/92	0	1	17	-14.2
1992/93[a]	2	2	14	-13.5

[a]Estimated.

SOURCE: Annual report on the working of State Electricity Boards and Electricity Departments. Planning Commission, Government of India, September 1990, August 1992.

Table D.9

Growth Rate of Electricity Tariffs
During the Period 1984/85 to 1989/90

SEB	Dom.[a]	Comm.[b]	Agri.[c]	Small Ind.[d]	Medium Ind.[e]	Large Ind.[f]	Total
Andhra Pradesh	5.23	6.55	0.00	10.07	11.78	11.56	6.14
Assam	1.61	7.54	10.76	6.75	10.52	13.11	11.93
Bihar	0.00	2.84	0.00	6.58	6.68	7.44	5.36
Gujarat	2.10	11.44	-12.03	9.62	6.93	11.90	3.05
Haryana	5.57	7.55	5.42	22.91	17.40	19.47	5.43
Himachel Pradesh	0.30	3.97	0.00	11.27	16.94	16.83	2.96
J&K	-1.24	8.45	0.00	18.41	15.17	17.66	9.53
Karnataka	7.95	11.23	8.45	17.32	15.70	18.16	6.32
Kerala	0.00	9.46	0.00	16.86	21.04	11.06	8.88
Madhya Pradesh	1.05	3.79	0.00	10.71	8.52	13.28	4.70
Maharashtra	3.25	10.24	-7.79	12.23	13.93	10.68	7.58
Orissa	2.34	12.45	14.15	10.64	9.84	13.43	6.81
Punjab	3.02	6.96	-0.04	11.61	14.24	14.15	3.76
Rajasthan	5.46	11.35	8.45	15.72	13.89	13.63	6.45
Tamil Nadu	0.60	7.90	-7.79	10.46	13.58	13.96	4.19
Uttar Pradesh	4.92	3.36	0.00	16.44	14.94	12.82	6.51
West Bengal	0.72	8.07	0.00	2.77	0.00	12.45	5.91
Goa	5.39	6.83	8.16	7.57	8.92	12.44	n.a.
Mizoram	8.75	7.96	9.46	27.12	27.68	24.20	n.a.
Nagaland	9.34	6.21	0.00	0.95	10.03	10.03	n.a.
Sikkim	5.14	9.86	9.86	9.86	6.43	8.33	n.a.
DESU	0.00	12.72	-5.29	15.47	15.47	13.47	n.a.

NOTE: 'Ind.' stands for industry.

[a]Domestic - 30 kWh/month
[b]Commercial - 200 kWh/month
[c]Agriculture - 5 Horse Power, 10 percent load factor, i.e. 272 kWh/month
[d]Small Industry - 5 Horse Power, 10 percent load factor, i.e. 272 kWh/month
[e]Medium Industry - 50 kW, 30 percent load factor, i.e. 10950 kWh/month
[f]Large Industry - 1000 kW, 50 percent load factor, i.e. 265000 kWh/month

SOURCE: Average electricity rates and duties in India, April 1990, Central Electricity Authority, Government of India.

Table D.10

Losses on Account of Supply of Electricity to the Agriculture Sector
(Rs. Crores)

Year	Supply of Agriculture	Supply of Domestic	Total Losses
1985/86	1237	250	1515
1986/87	1492	357	1608
1987/88	2366	466	2309
1988/89	2733	647	2918
1989/90	3317	821	4015
1990/91	2801	1056	3748
1991/92	5181	1223	4498
1992/93[a]	5880	1565	5121

[a]Estimated.

SOURCE: Annual report on the working of State Electricity Boards and Electricity Departments, Planning Commission, Government of India, September 1990, August 1992.

Table D.11

Average Electricity Tariffs and Average Cost of Supply,
(1991-1992)

State Electricity Board	Dom.	Comm.	Agri.	Industries LT	Industries HT	Industries PI	Railway Traction	Outside the State	Overall Average Rate	Overall Avg. Cost of Supply	Average Revenue/ Average Cost
Andhra Pradesh	64.2	135.0	4.5	97.4	119.0	120.0	131.0	0.0	70.6	72.1	0.98
Assam	60.0	108.1	50.0	60.4	99.2			110.0	94.5	254.8	0.37
Bihar	54.6	95.0	9.4	180.0	140.0		162.0	51.2	95.7	140.3	0.68
Gujarat	69.1	69.1	21.5	121.0	126.0		114.0	71.7	82.4	105.0	0.78
Haryana	56.0	123.0	30.0	116.0	107.0	88.0		86.0	61.6	105.2	0.59
Himachel Pradesh	43.5	82.5	20.0	71.6	71.6	71.6		46.2	56.8	95.0	0.60
Jamma and Kashmir	30.0	66.7	10.0	40.0					40.2	120.0	0.34
Karnataka	69.1	183.0	9.7	125.0	96.4				70.0	80.9	0.87
Kerala	48.7	78.0	22.0	60.0	57.9	54.7			56.3	65.3	0.86
Madhya Pradesh	20.1	112.7	25.9	97.6	120.0	106.0	158.0	102.0	84.8	98.1	0.86
Maharashtra	71.0	147.0	15.0	114.0	158.0		129.0		100.0	114.4	0.87
Meghalaya	44.0	68.0	21.0	55.0	55.0			47.0	50.6	123.3	0.41
Orissa	54.0	102.0	32.0	63.3	77.2	63.0	103.0		71.6	76.9	0 97
Punjab	74.5	106.5	7.5	74.8	81.8	79.4		70.3	49.9	106.1	0.46
Rajasthan	57.6	110.4	29.5	91.2	109.0			104.0	82.3	113.7	0.72
Tamil Nadu	57.0	110.3	8.9	106.0	100.0	100.0	106.0	48.0	71.7	112.0	0.64
Uttar Pradesh	65.3	97.2	21.3	118.0	133.0		129.0	34.8	77.3	111.9	0.69
West Bengal	58.7	100.4	24.5	80.5	96.1	60.4	89.6		99.8	136.6	0.72

NOTE: LT - Low Tension on Voltage; HT - High Tension on Voltage; and PI - Power Intensive.

SOURCE: Progress report No. 2, Environmentally sound energy development-India pilot project, submitted to United Nations environmental programme (UNEP), by TERI, January 1993.

Table D.12

Losses on Account of Rural Electrification
(Rs. Crores)

Year	Losses on Account	RE Subsidy Claimed as per SEBs' Accounts
1980/81	649.70	581.90
1981/82	735.20	549.60
1982/83	1083.50	643.40
1983/84	1243.70	732.70
1984/95	1551.90	850.40
1985/86	1845.20	1020.29
1986/87	2099.69	1002.01

NOTE: RE - rural electrification; and SEB - State Electricity Boards.

SOURCE: Progress report No. 2, Environmentally sound energy development-India pilot project, submitted to United Nations environmental programme (UNEP), by TERI, January 1993.

Table D.13

Financial Summary of State Electricity Boards 1991-92
(Rs. Crores)

Board	Revenue Receipts	Operating Expenditures	Gross Operating Surplus Deficit (3-4)	Depreci-ation	Interest Due to Institu-tions	Interest Due to State Govt.
Andhra Pradesh	1652.23	1169.00	483.23	108.35	183.03	132.70
Assam	141.62	215.25	-73.62	29.73	65.68	123.47
Bihar	595.74	782.35	-186.61	63.89	115.06	-
Gujarat	1525.62	1714.68	-189.06	130.75	165.31	96.26
Harnayana	634.41	720.78	-86.37	45.00	71.20	83.25
Himachel Pradesh	127.00	99.85	27.15	8.81	35.67	42.44
J&K	45.07	184.86	-139.79	13.72	28.22	35.37
Karnataka	892.66	838.56	54.1	34.56	71.58	34.37
K.P.C.[a]	383.81	196.55	187.26	26.86	52.34	71.23
Kerala	321.05	270.12	50.93	24.82	51.77	43.40
Madhya Pradesh	1514.87	1169.96	344.91	131.34	302.39	172.83
Maharashtra	3379.37	2683.64	698.73	217.54	407.39	238.34
Meghalaya	22.28	19.64	2.64	2.80	20.13	7.28
Orissa	368.70	236.36	132.34	39.92	73.90	25.22
Punjab	879.99	980.57	-100.58	91.20	92.98	276.91
Rajasthan	1060.47	941.03	119.44	80.24	96.68	61.22
Tamil Nadu	1731.41	1750.02	-18.61	110.53	203.70	100.07
Uttar Pradesh	1699.10	1763.68	-64.58	167.24	245.86	395.82
West Bengal	757.93	727.95	29.98	33.00	122.34	61.09
Total	17733.34	16464.85	1268.49	1360.30	2405.16	2001.30

[a]K.P.C. - Karnataka Power Corporation.

SOURCE: Annual report of the working of the State Electricity Boards and Electricity Departments, Planning Commission, Government of India, 1991.

Appendix E

DEFINITIONS AND ABBREVIATIONS

DEFINITIONS AND ABBREVIATIONS[1]

Alternating Current (AC): A current that flows alternately in one direction and then in the reverse direction. In North America the standard for alternating current is 60 complete cycles each second. Such electricity is said to have a frequency of 60 hertz. Alternating current is used universally in power systems because it can be transmitted and distributed much more economically than direct current.

Base Load: The minimum continuous load over a given period of time.

British Thermal Unit (Btu): A unit of heat. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Capacity: In the electric power industry, capacity has two meanings:

1. Installed System Capacity: The maximum power capability of a system. For example, a utility system might have a rated capacity of 5000 megawatts, or might sell 5000 megawatts of capacity (i.e. of power).

2. Station Capacity: The maximum power capability of a generating unit or station. For example, a generating unit might have a rated capacity of 50 megawatts.

Cogeneration: A cogenerating system produces electricity and heat in tandem. Such systems have great potential in industry, where a significant requirement for electricity is coupled with a large demand for process steam.

Consumer Price Index (CPI): A measure of the percentage change over time in the cost of purchasing a constant "basket" of goods and services. The basket consists of items for which there are continually measurable market prices, so that changes in the cost of the basket are due only to price movements.

Consumption: Use of electrical energy, over a specified period of time, typically measured in kilowatt hours.

Conventional Generation: Electricity that is produced at a generating station where the prime movers are driven by gases or steam produced by burning fossil fuels, or by water pressure operating directly on a turbine.

Current: The flow of electricity in a conductor. Current is measured in amperes.

Demand: Measure of instantaneous electricity demand at a specified point in time, typically measured in kilowatts. The rate of delivery of electrical energy, and the most frequently used measure of capacity.

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[1]Energy, Mines and Resources Canada, "Electric Power in Canada" (1991); Tata Energy Research Institute (1994).

Demand Charge: The component of a two-part price for electricity that is based on a customer's highest power demand reached in a specified period, usually a month, regardless of the quantity of energy used (e.g. $2.00 per kilowatt per month). The other component of the two-part price is the energy charge.

Direct Current (DC): Current that flows continuously in the same direction (as opposed to alternating current). The current supplied from a battery is direct current.

Economy Energy: Energy sold by one power system to another, to effect a saving in the cost of generation when the receiving party has adequate capacity to supply the loads from its own system.

Electrical Energy: The quantity of electricity delivered over a period of time. The commonly used unit of electrical energy is the kilowatt-hour (kWh).

Energy Charge: The component of a two-part price for electricity which is based on the amount of energy taken (e.g. 20 mills per kWh). The other component of the price is the demand charge.

Energy Source: The primary source that provides the power that is converted to electricity. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, geothermal, and other sources.

Firm Energy or Power: Electrical energy or power intended to be available at all times during the period of the agreement for its sale.

Frequency: The number of cycles through which an alternating current passes in a second. The North American standard is 60 cycles per second, known as 60 hertz.

Gigawatt (GW): One billion watts. (see Watt.)

Gigawatt hour (GWh): A unit of bulk energy. A million kilowatt hours. A billion watt hours.

Grid: A network of electric power lines and connections.

Gross Domestic Product (GDP): The total value of goods and services produced. GDP measured in constant dollars is defined as Real GDP.

Hertz (Hz): The unit of frequency for alternating current. Formerly called cycles per second. The standard frequency for power supply in North America is 60 Hz.

Interruptible Energy or Power: Energy or power made available under an agreement that permits curtailment of interruption of delivery at the option of the supplier.

Joule: The international unit of energy. The energy produced by a power of one watt flowing for one second. The joule is a very small unit: there are 3.6 million joules in a kilowatt hour.

Kilovolt (kV): 1000 volts.

Kilowatt (kW): The commercial unit of electric power; 1000 watts. A kilowatt can best be visualized as the total amount of power needed to light ten 100-watt light bulbs.

Kilowatt hour (kWh): The commercial unit of electric energy; 1000 watt hours. A kilowatt hour can best be visualized as the amount of electricity consumed by ten 100-watt light bulbs burning for an hour. One kilowatt hour is equal to 3.6 million joules.

Load: The amount of electric power or energy consumed by a particular customer or group of customers. Can be designated in terms of Demand or Consumption.

Load Factor: The ratio of the average load during a designated period to the peak load in that same period. (Usually expressed in percent).

Megawatt (MW): A unit of bulk power; 1000 kilowatts.

Megawatt hour (MWh): A unit of bulk energy; 1000 kilowatt hours.

Mill: 1/1000 of a dollar.

Net Exports: Total exports minus total imports.

Nuclear Power: Power generated at a station where the steam to drive the turbines is produced by an atomic process, rather than by burning a combustible fuel such as coal, oil or gas.

Peak Demand: The maximum power demand registered by a customer or a group of customers or a system in a stated period of time such as a month or a year. The value may be the maximum instantaneous load or more, usually the average load over a designated interval of time, such as one hour, and is normally stated in kilowatts or megawatts.

Plant Load Factor: For any equipment, the ratio of the average load during some time period to the rated capacity.

Power System: All the interconnected facilities of an electrical utility. A power system includes all the generation, transmission, distribution, transformation, and protective components necessary to provide service to the customers.

Primary Energy Source: The source of primary energy from which electricity is generated. This may be falling water, uranium (by nuclear fission), coal, oil, natural gas, wind, tidal energy, etc..

Reserve Generating Capacity: The extra generating capacity required on any power system over and above the expected peak load. Such a reserve is required mainly for two reasons: (i) in case of an unexpected breakdown of generating equipment; (ii) in case the actual peak load is higher than forecast.

Reserve Margin: In the Indian context, the available generating capacity is defined as the total system installed generating capacity, <u>less</u> planned outages, <u>less</u> forced outages, <u>less</u> partial outages. The difference between installed and available generation is referred to as the Reserve Margin.

Note that this differs from the Reserve Generating Capacity concept used in Canada, which would translate to the Partial Outages factor in the India situation.

Terawatt Hours (TWh): One billion kilowatt hours.

Voltage: The electrical force or potential that causes a current to flow in a circuit (just as pressure causes water to flow in a pipe). Voltage is measured in volts (V) or kilovolts (kV). 1 kV = 1000 V.

Watt: The scientific unit of electric power; a rate of doing work at the rate of one joule per second. A typical light bulb is rated 25, 40, 60 or 100 watts, meaning that it consumes that amount of power when illuminated. A horse power is 746 watts.

Appendix F

MODEL RESULTS FOR BUSINESS-AS-USUAL AND REFERENCE CASE

Appendix F

MODEL RESULTS FOR BUSINESS-AS-USUAL AND REFERENCE CASE

Introduction

The **ELITE** model was developed by the Alberta Research Council (ARC) specifically for the present study. The purpose of the model is to provide a comprehensive framework to assess the long term environmental goals and the future trends of electric power generation, transmission and trade in India. The database in the current model was developed by the Tata Energy Research Institute (TERI) and supplemented with data from the Canadian Energy Research Institute (CERI) and ARC.

The **ELITE** model is patterned after **ELGEM**, which is a Canadian model for long term planning of electric power generation and trade in Canada, with some additional features that are relevant to India, and perhaps to most developing countries as well. For examples, the financial resources necessary for the electric power industry to meet all its demands are not always available; there is the possibility of capacity shortfalls; and the losses in the electrical distribution systems are usually high. Other features can easily be added to help focus on the specific issues to be analyzed.

Model Description

ELITE is a linear programming, optimizing, long term electric power planning model for India. It is written in a software language called **OMNI** which is developed by the Haverly Systems Inc. of New Jersey, USA. The model has seven 5-year time periods and covers a planning horizon from 1991 to 2021.

The Indian electric power system is divided into five regions: **Northeast, North, East, West** and **South,** consistent with the division used by the Indian electric power industry.

Northeast:	all states and union territories east of West Bengal
North:	Uttar Pradesh, Rajasthan and other states and union territories to their north
East:	Bihar, West Bengal, Orissa and Sikkim
West:	Madhya Pradesh and other western states and union territories
South:	Four states of the south and Pondicherry

ELITE is very rich in technological description. The electric generating technologies currently in **ELITE** include hydro (of various sizes), nuclear, conventional pulverized coal (two sizes), various clean coal technologies, gas turbine, gas fired combined cycle, renewable and

cogeneration using different fuels. The list can be expanded when realistic data are available and all or only some of the technologies can be considered in a scenario.

The technological options are described in terms of their capital investment schedules, operating characteristics, costs and emission profiles. Emission profiles in the current **ELITE** include particulate, carbon dioxide, nitrogen oxides and sulphur dioxide. Long distance transmission lines which link supplies in one region to meet demand in another region are important part of the supply chain, are also modelled.

The important constraints in **ELITE** are:

- **capital availability, which is tied in to a percentage of Indian GDP;**
- **hydro potential, which can be set as a global limit;**
- **gas availability, which is forecasted as maximum volumes and to certain regions, by time period;**
- **coal production, which is forecasted as maximum allowable by time period.**

Demand-side management and decentralized generation (renewable) are assumed to operate outside of the public utilities so they are not included in the capital constraint. Emissions are not constrained in this version of **ELITE**, because of uncertainties in the data. It can easily be incorporated in the next version when more data become available.

The other data limitation is in regional electricity generation cost and coal production. Current data revealed that there is little cost difference for the same technology across regions and coal resources and rail-lines capacity limitation are not incorporated by region. Therefore the current data set does not allow evaluation of the regional electricity trade to its fullest extent.

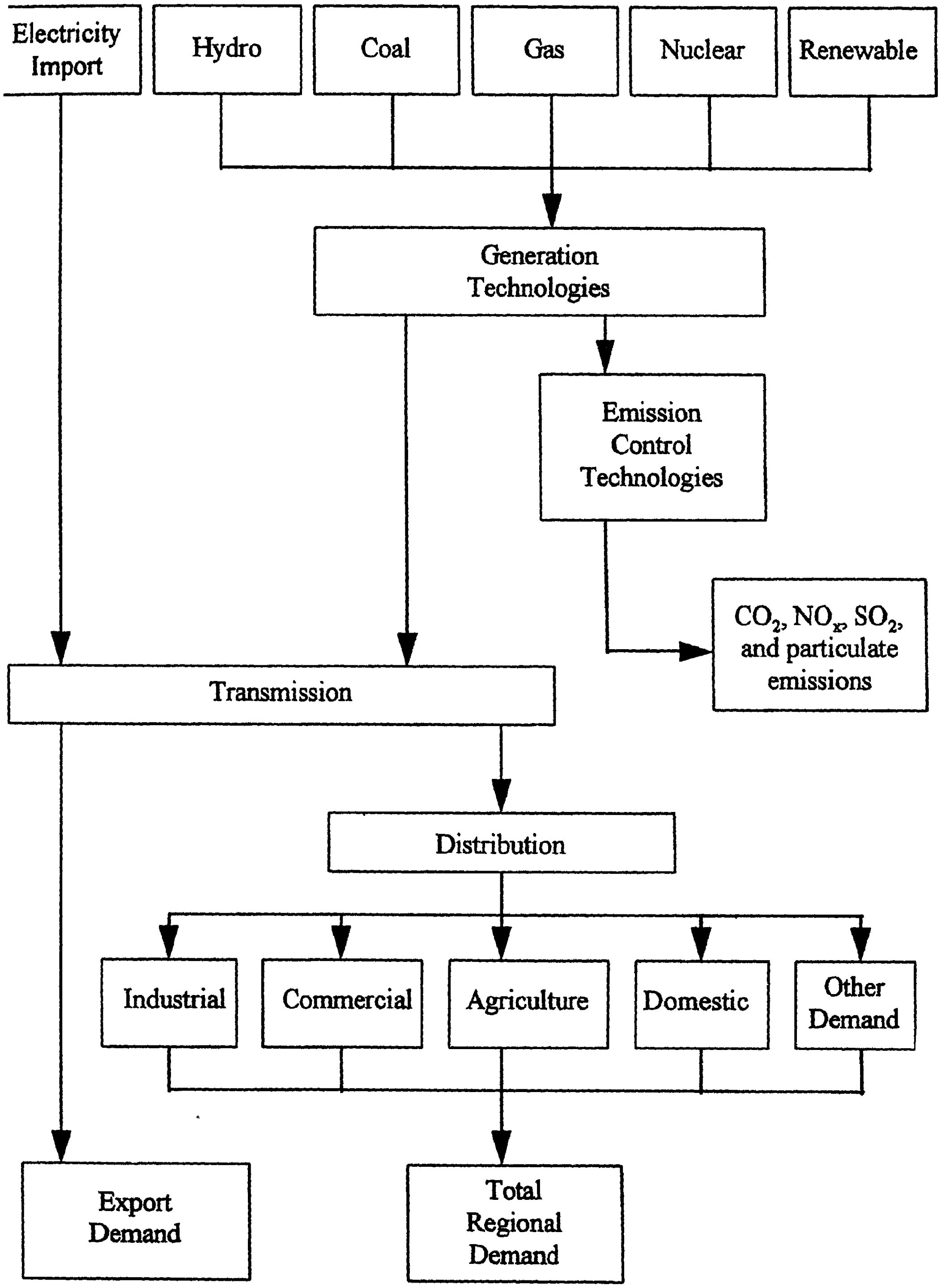
Other features in **ELITE** include the following.

Electric demand in **ELITE** is specified at the end use level and by sectors. The sectors are residential, commercial, industrial and others. This feature provides additional flexibility in that, 1) the demand-side management programs can be modelled in the sectoral level to reduce both peak and energy demand; 2) electricity distribution can be explicitly modelled. Hence, the impact of an efficiency improvement in the delivery of electricity to the consumers can be assessed.

Capacity shortfalls are captured. The model uses a generic peaking technology with the characteristics of a diesel generator and a generic base load technology with the characteristics of a conventional coal fired plant. The

Figure F.1

INDIA ELITE MODEL



demand shortages when they occurred will be met by these two generic technologies without drawing on any financial or resource constraints imposed in the scenario. The cost of the shortfalls are set high so that in normal situation, they would not be selected. The shortfalls will provide an estimate of the "**equivalent**" capacities that would be needed if all the demands are to be met.

Therefore, in the **ELITE** model, electric power demand by region at the sectorial level forms part of the input data; hence it is exogenous to the model For the demand to be satisfied, two conditions must be met.

- **there must be enough capacity to meet the forecast energy load, and**
- **there must be enough peak capacity to meet the peak power requirement.**

A schematic for the model (one region) is shown in Figure F.1. Please refer to the model listing for documentation of the equations in the model.

ELITE Model Outputs

For the period 1991-2021, given a demand forecast and the availability of capital and physical resources and the costs and operating characteristics of a set of electric generating options, that may include demand-side management and renewables, **ELITE** generates a capacity addition schedule by region and by fuel type that minimizes the present value of the costs. It also reports the shortfalls in capacities by region for both peak and energy, if and when they occurred. It summarizes the flow of electricity across regions and the regional transmission capacities required. It also provides a summary on the emission of particulate, CO_2, NO_x and SO_2 by region over the planning periods.

For Additional Information

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INDIAN ELITE

The Indian Electric
Inter-regional Transfer
and Emissions Model

Ver. 2.1 / Dec. 94

Developed by:
Ken Malak and Sam Wong

Alberta
Research
Council

Developed for: Canadian Energy Research Institute (CERI)

MODEL SOLUTION REPORT

For model run on: 15 DEC 94

With solution status: OPTM

OPTIMAL MINIMIZED SOLUTION IS: 457635 RUPEES CRORES

MODEL SIZE ROWS: 2903
COLUMNS: 3797

SCENARIO: BUSINESS AS USUAL - BAU
NO CAPITAL CONSTRAINT
NO COAL CONSTRAINT
NO RENEWABLE, NO DSH, NO CCT, NO COGEN

IMPORTANT CONSTRAINTS:

MAXIMUM CAPITAL INVESTMENT ALLOWED (RUPEE CRORES/TIME PERIOD)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	500000 0	207400 0	277000 0	371000 0	496100.0	663800.0	888400.0
ACTUAL INVESTMENT		69370.9	191816.7	211667.7	315041.1	447831.0	563328.2

MAXIMUM HYDROPOWER GENERATION CAPACITY (MW)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	30000.0	50000.0	50000.0	50000.0	60000.0	70000.0	80000 0
ACTUAL CAPACITY	19189 0	26409.8	35827.6	41177.0	47086.0	50871.0	53960.0

MAXIMUM GAS AVAILABLE IN NORTH, WEST AND SOUTH (MILLION M3)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	4200.0	9680.0	12000.0	12000.0	12000.0	12000.0	12000.0
ACTUAL USAGE	3170.9	8620.2	12000.0	12000.0	12000.0	12000.0	12000 0

MAXIMUM GAS AVAILABLE IN NORTH EAST (MILLION M3)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	2020 0	2020 0	2600.0	2600.0	2600.0	2600.0	2600.0
ACTUAL USAGE	101.4	97.5	390.2	660.6	1249.7	2598.6	2600 0

MAXIMUM GAS AVAILABLE IN EAST (MILLION M3)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	100.0	100.0	100.0	100.0	100.0	100.0	100.0

TABLE 1: ELECTRICITY DEMAND

1.1 NORTH-EAST INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	566.0	1247.0	2913.0	4415.0	7065.0	11255.0	17930.0
AVERAGE DEMAND	285.0	610.0	1467.0	2327.0	3828.0	6297.0	10359.0

1.2 NORTHERN INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	14533.0	17692.0	27330.0	36551.0	51241.0	71837.0	100709.0
AVERAGE DEMAND	8023.0	10750.0	16680.0	22530.0	31870.0	45090.0	63800.0

1 3 EASTERN INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	4451.0	6943.0	11187.0	15122.0	21126.0	29514.0	41232.0
AVERAGE DEMAND	2642.0	4296.0	6969.0	9501.0	13386.0	18809.0	26464.0

1.4 WESTERN INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	13585.0	17997.0	29063.0	42224.0	61008.0	88148 0	127361.0
AVERAGE DEMAND	8882.0	12701.0	20518 0	29855.0	43181.0	62455.0	90332.0

1.5 SOUTHERN INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	10537.0	13440.0	19987.0	27420.0	38500.0	54058.0	75903.0
AVERAGE DEMAND	6897.0	8716.0	12972.0	17899.0	25297.0	35753.0	50530.0

1.6 TOTAL INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	43672.0	57319.0	90480.0	125732.0	178940.0	254812.0	363135.0
AVERAGE DEMAND	26729.0	37073.0	58606.0	82112 0	117562.0	168404.0	241485.0

TABLE 2: ELECTRICITY GENERATION CAPACITY

2.1 INDIAN INSTALLED ELECTRIC GENERATION CAPACITY

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	1052.0	2114.8	5055.5	7259.3	11212.2	16865.1	27152.0
NORTHERN INDIA	20337.0	26769.3	41738.0	56693.3	82669.0	118786.3	165414.6
EASTERN INDIA	9193.0	9962.1	16379.9	23858.1	33057.2	47620.7	64352.7
WESTERN INDIA	21240.0	28968.9	48009.0	68781.8	100272.3	145401.6	208977.8
SOUTHERN INDIA	17248.0	21078.4	31599.8	43997.7	61070.8	85894.1	119652.6
INDIA TOTAL:	69070.0	88893.5	142782.1	200590.2	288281.6	414567.9	585549.9
% RESERVE MARGIN	36.8	35.5	36.6	37.3	37.9	38.5	38.0

2.2 INDIAN PEAK GENERATION CAPACITY

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	806.3	1768.3	4280.2	6139.1	9418.8	13866.5	22190.6
NORTHERN INDIA	17797.2	22923.4	34075.6	45243.1	64306.9	90271.3	126725.8
EASTERN INDIA	7063.9	7773.3	12565.8	18000.7	24713.3	35280.5	48832.9
WESTERN INDIA	16277.9	21652.7	35648.5	50829.1	73822.8	106749.6	153937.3
SOUTHERN INDIA	12936.0	15580.1	23458.9	32633.1	45187.8	63448.4	89556.0
INDIA TOTAL:	54881.2	69697.8	110029.0	152845.0	217449.7	309616.3	441242.7

2.3 INDIAN AVERAGE GENERATION

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	383.6	980.0	2490.6	3555.0	5412.6	7730.4	12820.5
NORTHERN INDIA	9577.5	14158.2	20628.6	27539.8	39848.6	56499.8	80123.6
EASTERN INDIA	3610.0	4595.7	7502.1	11252.8	15459.3	23318.5	31104.2
WESTERN INDIA	10618.5	15279.6	25365.7	35944.6	52370.3	75993.8	109377.8
SOUTHERN INDIA	8298.2	10035.5	15225.4	21458.2	30182.3	43853.5	59775.5
INDIA TOTAL:	32487.7	45049.0	71212.4	99750.3	143273.1	207396.1	293201.6

2.4 INSTALLED GENERATION CAPACITY BY FUEL TYPE

TYPE	1991	1996	2001	2006	2011	2016	2021
COAL	45509.0	46478.3	81768.3	133626.1	214242.1	334196.5	477209.1
NUCLEAR	1785.0	2814.0	4831.0	4751.0	4704.0	4690.0	4690.0
GAS	2587.0	13191.5	20355.3	21036.2	22249.5	24810.4	24813.0
HYDRO	19189.0	26409.8	35827.6	41177.0	47086.0	50871.0	53960.0
OTHER							24877.8
SHORTFALL							
INDIA TOTAL:	69070.0	88893.5	142782.1	200590.2	288281.6	414567 9	585549.9
% HYDRO (EX SF)	27.8	29.7	25.1	20.5	16.3	12.3	9.6

2.5 DECENTRALIZED GENERATION

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA TOTAL:							

2.6 DEMAND SIDE MANAGEMENT

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA TOTAL:							

2.7 CLEAN COAL TECHNOLOGIES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA TOTAL:							

TABLE 3: FINANCIAL SUMMARY

3.1 REAL COSTS IN RUPEE CRORES

YEAR	FUEL & VARIABLE	FIXED & CAPITAL	TOTAL
1991	63913		63913
1996	89918	58934	148852
2001	143537	189896	333433
2006	203512	299032	502544
2011	297822	489654	787476
2016	440330	754970	1195300
2021	624477	1075836	1700312
TOT	1863509	2868321	4731830

3.2 DISCOUNTED COSTS IN RUPEE CRORES

DISCOUNT RATE - 12%

YEAR	FUEL & VARIABLE	FIXED & CAPITAL	TOTAL
1991	63913		63913
1996	47453	31101	78554
2001	39975	52886	92861
2006	29911	43950	73861
2011	23100	37979	61079
2016	18024	30902	48926
2021	13489	23239	36728
TOT	235865	220058	455923

COST OF SHORTFALL: 1713

OPTIMAL SOLUTION: 457635

3.3 CAPITAL INVESTMENT IN GENERATION FACILITIES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA		2368	6583	4381	8473	10679	21877
NORTHERN INDIA		14038	28430	37414	61899	84639	83784
EASTERN INDIA		2603	15751	18033	22175	33974	26073
WESTERN INDIA		13774	44968	47882	70485	100745	133536
SOUTHERN INDIA		6225	25202	28123	37539	53609	62034
INDIA TOTAL.		39008	120934	135834	200572	283646	327304

3.4 CAPITAL INVESTMENT IN DISTRIBUTION FACILITIES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA		1051	2821	2831	4941	8128	13372
NORTHERN INDIA		8973	19916	19648	31369	44401	62839
EASTERN INDIA		4935	8536	8085	12406	17317	24445
WESTERN INDIA		11124	25022	29887	42656	61695	89233
SOUTHERN INDIA		4280	13288	15382	23097	32644	46135
INDIA TOTAL·		30363	69583	75834	114470	164185	236024

3.5 CAPITAL INVESTMENT IN INTRA-REGIONAL TRANSMISSION

NORTH TO EAST	400
EAST TO NORTH	
SOUTH TO EAST	
EAST TO SOUTH	400
N E TO EAST	500
EAST TO N.E.	
INDIA TOTAL·	1300

REAL COSTS IN 1991 (PAISE/KWH)

GENERATOR	REGION	ANNUAL CAPITAL P/KWH	FIXED COST P/KWH	VARIABLE COST P/KWH	'91 FUEL COST P/KWH	TOTAL COST P/KWH
EXISTING GENERATION						
HYDRO	N.E.			4.00		4.00
HYDRO	NORTH			4.00		4.00
HYDRO	EAST			4.00		4.00
HYDRO	WEST			4.00		4.00
HYDRO	SOUTH			4.00		4.00
COAL FIRED	N.E.			10.00	19.43	29.43
COAL FIRED	NORTH			10.00	19.82	29.82
COAL FIRED	EAST			10.00	22.62	32.62
COAL FIRED	WEST			10.00	20.10	30.10
COAL FIRED	SOUTH			10 00	26.51	36.51
GAS FIRED	N.E.			7.30	54.60	61.90
GAS FIRED	NORTH			7.30	70.80	78.10
GAS FIRED	EAST			7.30	70.80	78.10
GAS FIRED	WEST			7.30	70.80	78.10
GAS FIRED	SOUTH			7.30	70.80	78.10
NUCLEAR	NORTH			10.00	18.26	28.26
NUCLEAR	WEST			10.00	18.26	28.26
NUCLEAR	SOUTH			10.00	18.26	28.26

NEW GENERATION						
COAL 210 MW	N.E.	55.98	10.98	11.50	20.38	98.84
COAL 210 MW	NORTH	55.98	10.98	11.50	17.86	96.32
COAL 210 MW	EAST	55.98	10.98	11.50	20.38	98.84
COAL 210 MW	WEST	55.98	10.98	11.50	17.86	96.32
COAL 210 MW	SOUTH	55.98	10.98	11.50	22.90	101.36
COAL 500 MW	N.E.	42.81	8.39	11.50	19.10	81.81
COAL 500 MW	NORTH	42.81	8.39	11.50	16.74	79.45
COAL 500 MW	EAST	42.81	8.39	11.50	19.10	81.81
COAL 500 MW	WEST	42.81	8.39	11.50	16.74	79.45
COAL 500 MW	SOUTH	42.81	8.39	11.50	21.46	84.17
NUCLEAR	NORTH	68.74	9.66	10.00	18.26	106.66
NUCLEAR	WEST	68.74	9.66	10.00	18.26	106.66
NUCLEAR	SOUTH	68.74	9.66	10.00	18.26	106.66
HYDRO 60 MW	N.E.	61.44	12.56	4.00		77.99
HYDRO 60 MW	NORTH	61.44	12.56	4.00		77.99
HYDRO 60 MW	EAST	61.44	12.56	4.00		77.99
HYDRO 60 MW	WEST	68.26	13.95	4.00		86.22
HYDRO 60 MW	SOUTH	68.26	13.95	4.00		86.22
HYDRO 100MW	N E.	55.85	11.42	4.00		71.27
HYDRO 100MW	NORTH	55.85	11.42	4.00		71.27
HYDRO 100MW	EAST	55.85	11.42	4.00		71.27
HYDRO 100MW	WEST	62.06	12.68	4.00		78.74
HYDRO 100MW	SOUTH	62.06	12.68	4 00		78.74
GAS TUR 60MW	N.E.	.58.22	11.42	4.00	54 60	128.23
GAS TUR 60MW	NORT	58.22	11.42	4.00	70 80	144 43
GAS TUR 60MW	EAST	58.22	11.42	4.00	70 80	144.43
GAS TUR 60MW	WEST	58.22	11.42	4.00	70.80	144 43
GAS TUR 60MW	SOUT	58.22	11.42	4 00	70 80	144.43
LG HYDRO COST 1	N E.	51.20	8.56	4.00		63.76
LG HYDRO COST 1	NORTH	51.20	8.56	4.00		63.76
LG HYDRO COST 1	EAST	51.20	8.56	4 00		63.76
LG HYDRO COST 1	WEST	51.20	8.56	4.00		63.76
LG HYDRO COST 1	SOUTH	51.20	8.56	4.00		63.76
LG HYDRO COST 2	N E.	72.14	8.56	4.00		84.70
LG HYDRO COST 2	NORTH	72.14	8.56	4.00		84.70
LG HYDRO COST 2	EAST	72.14	8.56	4.00		84.70
LG HYDRO COST 2	WEST	72.14	8.56	4.00		84.70
LG HYDRO COST 2	SOUTH	72.14	8.56	4.00		84.70
LG HYDRO COST 3	N E.	107.05	8.56	4 00		119.61
LG HYDRO COST 3	NORTH	107.05	8.56	4.00		119 61
LG HYDRO COST 3	EAST	107.05	8.56	4.00		119.61
LG HYDRO COST 3	WEST	107.05	8.56	4 00		119 61
LG HYDRO COST 3	SOUTH	107.05	8.56	4 00		119.61
LG HYDRO COST 4	N E.	144.29	8.56	4.00		156 85
LG HYDRO COST 4	NORTH	144.29	8 56	4.00		156.85
LG HYDRO COST 4	EAST	144.29	8.56	4.00		156.85
LG HYDRO COST 4	WEST	144.29	8.56	4.00		156.85
LG HYDRO COST 4	SOUTH	144.29	8.56	4.00		156.85
GAS COMB. CYCLE	N.E.	35.83	4.18	8.50	54.60	103.10
GAS COMB. CYCLE	NORTH	35.83	4.18	8.50	70.80	119.30
GAS COMB. CYCLE	EAST	35.83	4.18	8.50	70.80	119.30
GAS COMB. CYCLE	WEST	35.83	4.18	8.50	70.80	119.30
GAS COMB. CYCLE	SOUTH	35.83	4.18	8.50	70 80	119.30
PEAK SHORTFALL	N.E.	291.10		90.00		381.10
PEAK SHORTFALL	NORTH	291.10		90.00		381.10
PEAK SHORTFALL	EAST	291.10		90.00		381.10
PEAK SHORTFALL	WEST	291.10		90.00		381.10
PEAK SHORTFALL	SOUTH	291.10		90.00		381.10
AVG. SHORTFALL	N E.	121.29	95.13	90.00		306.42
AVG. SHORTFALL	NORTH	121.29	95.13	90.00		306.42
AVG. SHORTFALL	EAST	121.29	95.13	90.00		306.42
AVG. SHORTFALL	WEST	121.29	95.13	90.00		306 42
AVG. SHORTFALL	SOUTH	121.29	95.13	90.00		306.42

TABLE 5: INSTALLED CAPACITY (IN MW)

TYPE		1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION								
HYDRO	A	426.0	409.0	389.0	370.0	359.0	350.0	350.0
HYDRO	N	6252.0	6009.0	5711.0	5431.0	5270.0	5200.0	5200.0
HYDRO	E	1501.0	1442.0	1371.0	1304.0	1265.0	1250.0	1250.0
HYDRO	W	2720.0	2613.0	2485.0	2363.0	2293.0	2250.0	2250.0
HYDRO	S	8290.0	7963.0	7573.0	7202.0	6988.0	6900.0	6900.0
COAL FIRED	A	240.0	231.0	219.0	208.0	202.0	200.0	200.0
COAL FIRED	N	12004.0	11531.0	11077.0	10428.0	10119.0	10000.0	10000.0
COAL FIRED	E	7502.0	7206.0	6853.0	6517.0	6324.0	6300.0	6300.0
COAL FIRED	W	17341.0	16658.0	15841.0	15065.0	14617.0	14000.0	14000.0
COAL FIRED	S	8422.0	8090.0	7694.0	7317.0	7099.0	7000.0	7000.0
GAS FIRED	A	386.0	371.0	353.0	335.0	325.0	320.0	320.0
GAS FIRED	N	1186.0	1139.0	1083.0	1030.0	1000.0	1000.0	1000.0
GAS FIRED	E	190.0	183.0	174.0	165.0	160.0	150.0	150.0
GAS FIRED	W	759.0	729.0	693.0	659.0	640.0	640.0	640.0
GAS FIRED	S	66.0	63.0	60.0	57.0	56.0	55.0	55.0
NUCLEAR	N	895.0	860.0	818.0	778.0	754.0	750.0	750.0
NUCLEAR	W	420.0	403.0	384.0	365.0	354.0	350.0	350.0
NUCLEAR	S	470.0	451.0	429.0	408.0	396.0	390.0	390.0
TOTAL EXISTING:		69070.0	66351.0	63207.0	60002.0	58221.0	57105.0	57105.0

TABLE 6: UTILIZATION OF CAPACITY (IN MW)

TYPE		1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION								
HYDRO	A	213.0	204.5	194.5	185.0	179.5	175.0	175.0
HYDRO	N	3438.6	3304.9	3141.1	2987.1	2898.5	2080.0	2860.0
HYDRO	E	750.5	721.0	685.5	652.0	126.5	125.0	625.0
HYDRO	W	1224.0	1175.8	1118.3	1063.3	1031.8	225.0	225.0
HYDRO	S	3730.5	3583.4	3407.9	3088.0	2795.2	2760.0	2760.0
COAL FIRED	A	132.0	115.5	120.4	114.4	101.0	110.0	100.0
COAL FIRED	N	4890.3	6425.8	6330.6	4171.2	4047.6	4000.0	4000.0
COAL FIRED	E	2840.5	3245.1	2398.6	2280.9	2213.4	2205.0	2205.0
COAL FIRED	W	8687.1	9994.8	7920.5	7532.5	7308.5	7000.0	7000.0
COAL FIRED	S	4246.1	4854.0	3847.0	3658.5	3549.5	3500.0	3500.0
GAS FIRED	A	38.6	37.1	35.3	33.5	32.5	32.0	32.0
GAS FIRED	N	711.6	683.4	649.8	618.0	600.0	600.0	600.0
GAS FIRED	E	19.0	18.3	17.4	16.5	16.0	15.0	15.0
GAS FIRED	W	455.4	437.4	415.8	395.4	384.0	384.0	384.0
GAS FIRED	S	39.6	37.8	36.0	34.2	33.6	33.0	33.0
NUCLEAR	N	537.0	516.0	490.8	466.8	377.0	375.0	375.0
NUCLEAR	W	252.0	241.8	230.4	182.5	177.0	175.0	175.0
NUCLEAR	S	282.0	270.6	257.4	204.0	198.0	195.0	195.0
TOTAL EXISTING:		32487.7	35867.3	31297.2	27683.9	26069.6	23989.0	25259.0
NEW GENERATION								
COAL 210 MW	A							3005.6
COAL 210 MW	N			2035.6	10453.8	26053.6	49851.8	73790.1
COAL 210 MW	E		18.0	3265.9	7480.2	12471.1	20419.7	26779.0
COAL 210 MW	W		1092.0	8548.0	17117.5	29872.9	48190.3	72469.5
COAL 210 MW	S			2795.0	6329.2	11334.4	18482.2	26753.4
COAL 500 MW	A							3005.6
COAL 500 MW	N			1017.8	5226.9	13026.8	24925.9	36895.1
COAL 500 MW	E		14.4	2612.7	5984.1	9976.9	16335.7	21423.2
COAL 500 MW	W		1637.9	12822.0	25676.3	44809.4	72285.4	108704.3
COAL 500 MW	S			6987.4	15823.0	28336.0	46205.5	66883.4
NUCLEAR	N		400.0	1100.0	1100.0	1100.0	1100.0	1100.0
NUCLEAR	W		400.0	1100.0	1100.0	1100.0	1100.0	1100.0
NUCLEAR	S		300.0	1000.0	1000.0	1000.0	1000.0	1000.0
HYDRO 60 MW	A			300.0	600.0	900.0	1200.0	1500.0
HYDRO 60 MW	N		440.0	1190.0	1940.0	2690.0	3300.0	3300.0
HYDRO 60 MW	E		100.0	300.0	500.0	650.0	650.0	650.0
HYDRO 60 MW	W		100.0	300.0	500.0	650.0	650.0	650.0
HYDRO 60 MW	S		120.0	320.0	450.0	450.0	450.0	450.0
HYDRO 100MW	A		300.0	600.0	900.0	1200.0	1500.0	1800.0
HYDRO 100MW	N		900.0	2500.0	4100.0	5300.0	5300.0	5300.0
HYDRO 100MW	E		200.0	400.0	400.0	400.0	400.0	400.0
HYDRO 100MW	W		200.0	200.0	200.0	200.0	200.0	200.0
HYDRO 100MW	S		250.0	500.0	500.0	500.0	500.0	500.0
GAS TUR 60MW	A			565.9	1089.4	2215.2	4784.1	4786.7
GAS TUR 60MW	N		2490.3	9205.6	9205.6	9355.6	9358.6	9358.6
GAS TUR 60MW	E		98.8	103.3	107.8	110.3	115.3	115.3
GAS TUR 60MW	W		4676.0	4676.0	4676.0	4676.0	4676.0	4676.0
GAS TUR 60MW	S		3441.4	3441.4	3711.4	3711.4	3711.4	3711.4
LG HYDRO COST 1A			803.8	1803.8	2803.8	3803.8	4603.8	5500.0
LG HYDRO COST 1N			2000.0	4000.0	4000.0	4000.0	4000.0	4000.0
LG HYDRO COST 1E			400.0	700.0	700.0	700.0	700.0	700.0
LG HYDRO COST 1W			260.0	560.0	560.0	560.0	560.0	560.0
LG HYDRO COST 1S			200.0	400.0	600.0	600.0	600.0	600.0
LG HYDRO COST 2A				824.8	953.2	2207.2	3707.2	5500.0
LG HYDRO COST 2N			1000.0	2000.0	3000.0	4000.0	4000.0	4000.0
LG HYDRO COST 2E			300.0	600.0	700.0	700.0	700.0	700.0
LG HYDRO COST 2W			200.0	400.0	500.0	500.0	500.0	500.0
LG HYDRO COST 2S			200.0	400.0	600.0	600.0	600.0	600.0
LG HYDRO COST 3A								
LG HYDRO COST 3N								
LG HYDRO COST 3E						300.0	600.0	600.0
LG HYDRO COST 3W								
LG HYDRO COST 3S								
LG HYDRO COST 4A								
LG HYDRO COST 4N								
LG HYDRO COST 4E								
LG HYDRO COST 4W								
LG HYDRO COST 4S								
GAS COMB. CYCLEA								
GAS COMB. CYCLEN								
GAS COMB. CYCLEE								
GAS COMB. CYCLEW								
GAS COMB. CYCLES								
PEAK SHORTFALL A								1184.0
PEAK SHORTFALL N								10720.9
PEAK SHORTFALL E								5285.3
PEAK SHORTFALL W								2878.1
PEAK SHORTFALL S								4809.4
AVG. SHORTFALL A								
AVG. SHORTFALL N								
AVG. SHORTFALL E								
AVG. SHORTFALL W								
AVG. SHORTFALL S								
TOTAL NEW:			22542.5	79575.1	140588 2	230060 6	357442 9	528444.9
TOTAL CAPACITY:		69070 0	88893.5	142782.1	200590 2	288261 6	414567 9	585549.9

EM GENERATION								
OAL 210 MW	A							1653.1
OAL 210 MW	N			1323 1	5966 3	14329 5	27418.5	40584 6
OAL 210 MW	E		11.7	1796 2	4114 1	6859 1	11230 8	14728 4
OAL 210 MW	W		709.8	4701.4	9414 6	16430 1	26504 6	39858 2
OAL 210 MW	S			1537.2	3481.1	6233.9	10165.2	14734 3
.OAL 500 MW	A							1653.1
:OAL 500 MW	N			692.1	3554.3	7164.7	13709.2	20292 3
:OAL 500 MW	E		9.8	1453 8	3291 3	5487.3	8984.7	11782 7
COAL 500 MW	W		1113.8	8719.0	15030.0	24645 2	39757.0	59787.3
COAL 500 MW	S			3952.6	8702 7	15584 8	25413 0	36785.9
NUCLEAR	N		260.0	715.0	715.0	440.0	440.0	440 0
NUCLEAR	W		260 0	524.2	440 0	440 0	440.0	440 0
NUCLEAR	S		195.0	650.0	400.0	400 0	400 0	400 0
H~DRO 60 MW	A			150.0	300.0	450 0	600 0	750.0
HYDRO 60 MW	N		220.0	595.0	970.0	807 0	990 0	1650 0
HYDRO 60 MW	E		50.0	150.0	150 0	195 0	195 0	325.0
HYDRO 60 MW	W		45.0	135.0	225.0	292 5	195 0	195.0
HYDRO 60 MW	S		54.0	144 0	202 5	135 0	135 0	135 0
HYDRO 100MW	A		140.6	300.0	450.0	600 0	750 0	900 0
HYDRO 100MW	N		450.0	1250 0	2050.0	2650 0	1590 0	2650 0
HYDRO 100MW	E		100.0	200.0	120 0	120.0	120 0	200 0
HYDRO 100MW	W		90.0	90.0	90.0	90 0	60 0	60 0
HYDRO 100MW	S		112.5	225.0	225.0	150 0	150 0	150 0
GAS TUR 60MW	A			113.2	217 9	443 0	956 8	957 3
GAS TUR 60MW	N		498.3	1841 1	1841.1	1871 1	1871 7	1871 7
GAS TUR 60MW	E		19 8	20.7	21 6	22 1	23 1	23 1
GAS TUR 60MW	W		935 2	935.2	935 2	935 2	935 2	935 2
GAS TUR 60MW	S		688.3	688.3	742 3	742 3	742 3	742 3
LG HYDRO COST	1A		482.3	1082.3	1682 3	2282 3	2882 3	3300 0
LG HYDRO COST	1N		1200.0	2400 0	2400.0	2400 0	1200 0	2400 0
LG HYDRO COST	1E		240.0	420.0	210.0	210.0	210 0	420 0
LG HYDRO COST	1W		158.0	336.0	336.0	336 0	168 0	168 0
LG HYDRO COST	1S		120.0	240.0	360.0	180 0	180 0	180 0
LG HYDRO COST	2A			494 9	571 9	1324 3	2224.3	3300 0
LG HYDRO COST	2N		600.0	1200.0	1800 0	2263.3	2225.4	2400 0
LG HYDRO COST	2E		180 0	360 0	396 4	210 0	210 0	420 0
LG HYDRO COST	2W		120 0	240 0	300 0	300 0	150.0	150 0
LG HYDRO COST	2S		120.0	240 0	360 0	180 0	180.0	180 0
LG HYDRO COST	3A							
LG HYDRO COST	3N							
LG HYDRO COST	3E							360 0
LG HYDRO COST	3W							
LG HYDRO COST	3S							
LG HYDRO COST	4A							
LG HYDRO COST	4N							
LG HYDRO COST	4E							
LG HYDRO COST	4W							
LG HYDRO COST	4S							
GAS COMB CYCLE	A							
GAS COMB. CYCLE	N							
GAS COMB CYCLE	E							
GAS COMB CYCLE	W							
GAS COMB. CYCLE	S							
PEAK SHORTFALL	A							
PEAK SHORTFALL	N							
PEAK SHORTFALL	E							
PEAK SHORTFALL	W							
PEAK SHORTFALL	S							
AVG SHORTFALL	A							
AVG. SHORTFALL	N							
AVG SHORTFALL	E							
AVG SHORTFALL	W							
AVG SHORTFALL	S							
TOTAL NEW			9181 7	39915 3	72066 4	117203.5	183407 1	267942 6
TOTAL CAPACITY.		32487 7	45049.0	71212.4	99750 3	143273.2	207396.1	293201 6

TABLE 7: ENERGY RESOURCE CONSUMPTION

7.1 CONSUMPTION OF HYDROPOTENTIAL IN MW

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	213	826	2219	3185	4830	6623	8414
NORTH	3434	5767	8574	10193	11004	8074	11944
EAST	749	1289	1813	1526	860	859	2347
WEST	1222	1585	1917	2012	2048	797	797
SOUTH	3725	3984	4251	4230	3436	3400	3400
SUM:	9344	13452	18774	21146	22177	19753	26901

7.2 CONSUMPTION OF COAL DOM A1 IN 000 TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N E.	694	607	633	601	531	578	18193
NORTH	29987	39403	49698	76875	140932	246700	353385
EAST	17418	20014	32135	53702	79787	121938	155702
WEST	54030	71837	120271	176488	263507	395291	572512
SOUTH	27153	31040	53513	87585	137650	209826	293711
SUM:	129282	162902	256251	395251	622407	974333	1393503

7.3 CONSUMPTION OF NATURAL GAS IN 000 000m3

REGION	1991	1996	2001	2006	2011	2016	2021
N E	101	97	390	661	1250	2599	2600
NORTH	1870	3105	6546	6463	6494	6496	6496
EAST	50	100	100	100	100	100	100
WEST	1197	3607	3550	3497	3467	3467	3467
SOUTH	104	1908	1903	2041	2039	2037	2037
SUM:	3322	8818	12490	12761	13350	14699	14700

7.4 CONSUMPTION OF FUEL OIL IN 000 m^3

REGION	1991	1996	2001	2006	2011	2016	2021
N E.	6	5	5	5	4	5	149
NORTH	214	281	366	600	1119	1977	2842
EAST	124	143	247	424	638	982	1258
WEST	380	518	935	1401	2119	3209	4671
SOUTH	186	213	409	694	1111	1712	2409
SUM:	911	1160	1962	3123	4991	7884	11329

7.5 CONSUMPTION OF NUCLEAR FUEL IN kg U

REGION	1991	1996	2001	2006	2011	2016	2021
N E.							
NORTH	429486	620636	964384	945189	653427	651827	651827
EAST							
WEST	201547	401334	603551	497868	493469	491870	491870
SOUTH	225540	372381	725728	483072	478273	475874	475874
SUM:	856573	1394350	2293663	1926129	1625169	1619571	1619571

TABLE 8. ENVIRONMENTAL EMISSIONS

8.1 EMISSIONS OF PARTICULATES IN TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	22201	19426	20259	19241	16987	18501	102258
NORTH	959585	1260902	1300103	1086706	1415592	1973816	2544724
EAST	557380	637345	557790	646515	765996	975743	1144870
WEST	1727438	2030894	1884863	2077901	2439216	2982402	3783697
SOUTH	870374	994992	908225	1016758	1205420	1496607	1845299
SUM:	4136978	4943559	4671239	4847121	5843211	7447070	9420847

8.2 EMISSIONS OF CARBON DIOXIDE IN 000 TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	1371	1217	1846	2333	3393	6170	35959
NORTH	54290	72632	96914	142735	251025	429749	610017
EAST	29462	33939	54455	90919	135019	206278	263359
WEST	93712	128646	210518	305506	452648	675597	975410
SOUTH	45959	56117	94197	152151	236895	359062	501049
SUM:	224793	292551	457930	693645	1078980	1676857	2385795

8.3 EMISSIONS OF SULPHUR DIOXIDE IN TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	6692	5865	9082	11526	16772	30722	198218
NORTH	288889	392030	525144	782773	1392943	2399170	3414116
EAST	166766	192125	307092	512177	760229	1161105	1482202
WEST	511057	704285	1165362	1699859	2527098	3779832	5464307
SOUTH	256753	311583	525406	850614	1326323	2012093	2809102
SUM:	1230158	1605887	2532086	3856949	6023365	9382921	13367944

8.4 EMISSIONS OF NITROGEN OXIDES IN TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	7089	6276	8950	10917	15192	26859	185690
NORTH	285467	380503	502124	746983	1325641	2280436	3243481
EAST	157179	180964	290392	484947	720239	1100440	1404992
WEST	497004	677560	1113195	1619347	2403249	3590605	5187346
SOUTH	246357	296540	498548	806389	1257052	1906780	2661946
SUM:	1193097	1541842	2413209	3668582	5721374	8905119	12683455

8.5 GENERATION OF NUCLEAR WASTE IN 000 M3

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.							
NORTH	4986	7206	11197	10974	7586	7568	7568
EAST							
WEST	2340	4660	7007	5780	5729	5711	5711
SOUTH	2619	4323	8426	5609	5553	5525	5525
SUM:	9945	16189	26630	22363	18868	18803	18803

TABLE 9A: NORTH-EAST INDIA SUPPLY / DEMAND BALANCES

9A.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	426.0	409.0	389.0	370.0	359.0	350.0	350.0
COAL FIRED	240.0	231.0	219.0	208.0	202.0	200.0	200.0
GAS FIRED	386.0	371.0	353.0	335.0	325.0	320.0	320.0
TOTAL EXISTING:	1052.0	1011.0	961.0	913.0	886.0	870.0	870.0
NEW GENERATION							
COAL 210 MW							3005.6
COAL 500 MW							3005.6
HYDRO 60 MW			300.0	600.0	900.0	1200.0	1500.0
HYDRO 100MW		300.0	600.0	900.0	1200.0	1500.0	1800.0
GAS TUR 60MW			565.9	1089.4	2215.2	4784.1	4786.7
LG HYDRO COST 1		803.8	1803.8	2803.8	3803.8	4803.8	5500.0
LG HYDRO COST 2			824.8	953.2	2207.2	3707.2	5500.0
LG HYDRO COST 3							
LG HYDRO COST 4							
GAS COMB CYCLE							
PEAK SHORTFALL							1184.0
AVG. SHORTFALL							
TOTAL NEW:		1103 8	4094.5	6346.3	10326.2	15995.1	26282.0
TOTAL CAPACITY:	1052.0	2114.8	5055.5	7259.3	11212.2	16865.1	27152.0

9A.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	298.2	286.3	272.3	259.0	251.3	245.0	245.0
COAL FIRED	180.0	173.3	164 3	156.0	151.5	150.0	150.0
GAS FIRED	328.1	315.4	300.1	284.8	276.3	272.0	272.0
NEW PEAK CAPACITY							
COAL 210 MW							2103.9
COAL 500 MW							2254.2
HYDRO 60 MW			270.0	540.0	810.0	1080.0	1350.0
HYDRO 100MW		270.0	540.0	810.0	1080.0	1350.0	1620.0
GAS TUR 60MW			367.9	708.1	1439.9	3109.7	3111.4
LG HYDRO COST 1		723.4	1623.4	2523.4	3423.4	4323.4	4950.0
LG HYDRO COST 2			742.3	857.8	1986.5	3336.5	4950.0
PEAK SHORTFALL							1184.0
PEAK GENERATION.	806.3	1768.3	4280.2	6139.1	9418.8	13866.5	22190.6
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM E						62.9	
-EXPORT TO E	30 9	225 0	675.0	675 0	675.0		
MAX PEAK SUPPLY:	775.4	1543 3	3605.2	5464.1	8743.8	13929.5	22190 6
-SURPLUS PEAK	74.9						
=DISTRIBUTION	700.5	1543.3	3605.2	5464.1	8743.8	13929.5	22190.6
-DIST LOSSES	134.5	296.3	592.2	1049.1	1678.8	2674.5	4260.6
+OSM GENER.							
+DECENT. GENER							
=PEAK DEMAND	566.0	1247 0	2913.0	4415.0	7065.0	11255.0	17930.0

9A.3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS							
SOLAR THERMAL							
MICRO HYDEL							
PHOTOVOLTAIC							
WIND POWER							
TOTAL:							

9A.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	213.0	204.5	194.5	185.0	179.5	175.0	175.0
+COAL FIRED	132.0	115.5	120.4	114.4	101.0	110.0	100.0
+GAS FIRED	38.6	37.1	35.3	33.5	32.5	32.0	32.0
NEW SITES							
+COAL 210 MW							1653.1
+COAL 500 MW							1653.1
+HYDRO 60 MW			150.0	300.0	450.0	600.0	750.0
+HYDRO 100MW		140.6	300.0	450.0	600.0	750.0	900.0
+GAS TUR 60MW			113.2	217.9	443.0	956.8	957.3
+LG HYDRO COST 1		482.3	1082.3	1682.3	2282.3	2882.3	3300.0
+LG HYDRO COST 2			494.9	571.9	1324.3	2224.3	3300.0
+PEAK SHORTFALL							
=TOTAL:	383.6	980.0	2490.6	3555.0	5412.6	7730.4	12820.5
+IMPORT FROM E						62.9	
-EXPORT TO E	30.9	225.0	675.0	675.0	675.0		
=MAX AVG. SUPPLY:	352.7	755.0	1815.6	2880.0	4737.6	7793.3	12820.5
-SURPLUS AVG							
=DISTRIBUTION.	352.7	755.0	1815.6	2880.0	4737.6	7793.3	12820.5
-DIST LOSSES	67.7	145.0	348.6	553.0	909.6	1496.3	2461.5
+DSM GENER							
+DECENT. GENER							
=AVG DEMAND	285.0	610.0	1467.0	2327.0	3828.0	6297.0	10359.0

TABLE 9N: NORTHERN INDIA SUPPLY / DEMAND BALANCES

9N.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	6252.0	6009.0	5711.0	5431.0	5270.0	5200.0	5200.0
COAL FIRED	12004.0	11531.0	11077.0	10428.0	10119.0	10000.0	10000.0
GAS FIRED	1186.0	1139.0	1083.0	1030.0	1000.0	1000.0	1000.0
NUCLEAR	895.0	860.0	818 0	778.0	754.0	750.0	750.0
TOTAL EXISTING:	20337.0	19539.0	18689.0	17667.0	17143.0	16950.0	16950.0
NEW GENERATION							
COAL 210 MW			2035.6	10453.8	26053.6	49851.8	73790.1
COAL 500 MW			1017.8	5226.9	13026.8	24925.9	36895.1
NUCLEAR		400.0	1100.0	1100.0	1100.0	1100.0	1100.0
HYDRO 60 MW		440.0	1190.0	1940.0	2690.0	3300.0	3300.0
HYDRO 100MW		900.0	2500.0	4100.0	5300.0	5300.0	5300.0
GAS TUR 60MW		2490.3	9205.6	9205.6	9355.6	9358.6	9358.6
LG HYDRO COST 1		2000.0	4000.0	4000.0	4000.0	4000.0	4000.0
LG HYDRO COST 2		1000.0	2000.0	3000.0	4000.0	4000.0	4000.0
LG HYDRO COST 3							
LG HYDRO COST 4							
GAS COMB. CYCLE							
PEAK SHORTFALL							10720.9
AVG. SHORTFALL							
TOTAL NEW:		7230.3	23049.0	39026.3	65526.0	101836.3	148464.6
TOTAL CAPACITY:	20337.0	26769.3	41738.0	56693.3	82669.0	118786.3	165414.6

9N.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	5314.2	5107.7	4854.4	4616.4	4479.5	4420.0	4420.0
COAL FIRED	10803.6	10377.9	9969.3	9385.2	9107.1	9000.0	9000.0
GAS FIRED	1008.1	968.2	920.6	875.5	850.0	850.0	850.0
NUCLEAR	671.3	645.0	613.5	583.5	565.5	562.5	562.5
NEW PEAK CAPACITY							
COAL 210 MW			1424.9	7317.7	18237.5	34896.3	51653.1
COAL 500 MW			763.3	3920.2	9770.1	18694.4	27671.3
NUCLEAR		300.0	825.0	825.0	825.0	825.0	825.0
HYDRO 60 MW		396.0	1071.0	1746.0	2421.0	2970.0	2970.0
HYDRO 100MW		810.0	2250.0	3690 0	4770.0	4770.0	4770.0
GAS TUR 60MW		1618.7	5983.7	5983.7	6081.2	6083.1	6083.1
LG HYDRO COST 1		1800.0	3600.0	3600.0	3600.0	3600.0	3600.0
LG HYDRO COST 2		900.0	1800.0	2700.0	3600.0	3600.0	3600.0
PEAK SHORTFALL							10720.9
PEAK GENERATION:	17797.2	22923.4	34075.6	45243.1	64306.9	90271.3	126725.8
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM E	129.6			475 2			
+IMPORT FROM W	423 0		432.0	432 0	391.3	432 0	432.0
-EXPORT TO E		135.0					
-EXPORT TO W		450.0					
MAX PEAK SUPPLY:	18349.7	22338.4	34507.6	46150.3	64698.2	90703.3	127157.8
-SURPLUS PEAK							
-DISTRIBUTION	18349.7	22338.4	34507.6	46150.3	64698.2	90703.3	127157.8

-DIST LOSSES	3816.7	4646.4	7177.6	9599.3	13457.2	18866 3	26448.8
+DSM GENER.							
+DECENT. GENER.							
-PEAK DEMAND	14533.0	17692.0	27330.0	36551 0	51241.0	71837.0	100709.0

9N 3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS							
SOLAR THERMAL							
MICRO HYDEL							
PHOTOVOLTAIC							
WIND POWER							
TOTAL.							

9N.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	3438.6	3304.9	3141.1	2987.1	2898.5	2080 0	2880 0
+COAL FIRED	4890.3	6425.8	6330 6	4171.2	4087 6	4000 0	4000 0
+GAS FIRED	711.6	683 4	649.8	618.0	600.0	600 0	600.0
+NUCLEAR	537.0	516.0	490 8	466.8	377.0	375 0	375 0
NEW SITES							
+COAL 210 MW			1323.1	5966.3	14329 5	27418.5	40584 6
+COAL 500 MW			692 1	3554.3	7164 7	13709 2	20292 3
+NUCLEAR		260 0	715 0	715 0	440 0	.440 0	440 0
+HYDRO 60 MW		220.0	595 0	970.0	807.0	990 0	1650 0
+HYDRO 100MW		450.0	1250 0	2050 0	2650 0	1390 0	2650 0
+GAS TUR 60MW		498.1	1841 1	1841 1	1871.1	1871 7	1871 7
+LG HYDRO COST 1		1200.0	2400 0	2400.0	2400 0	1200 0	2400 0
+LG HYDRO COST 2		600.0	1200 0	1800.0	2263.1	2225 4	2400 0
+PEAK SHORTFALL							
-TOTAL:	9577 5	14158.2	20628 6	27539 8	39848 6	56499 8	80123 6
+IMPORT FROM E	129 6			475 2			
+IMPORT FROM W	423.0		432 0	432 0	391.3	432 0	432 0
-EXPORT TO E		135 0					
-EXPORT TO W		450 0					
-MAX AVG SUPPLY:	10130.1	13573 2	21060 6	28447 0	40739.9	56931 8	80555 6
-SURPLUS AVG.							
-DISTRIBUTION:	10130.1	13573.2	21060 6	28447 0	40239 9	56931 8	80555 6
-DIST LOSSES	2107.1	2823.2	4380.6	5917.0	8369.9	11841 8	16755 6

+DSM GENER.							
+DECENT. GENER.							
-AVG. DEMAND	8023.0	10750.0	16680.0	22530.0	31870.0	45090.0	63800.0

TABLE 9E: EASTERN INDIA
SUPPLY / DEMAND BALANCES

9E.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	1501.0	1442.0	1371.0	1304.0	1265.0	1250.0	1250.0
COAL FIRED	7502.0	7206.0	6853.0	6517.0	6324.0	6300.0	6300.0
GAS FIRED	190.0	183.0	174.0	165.0	160.0	150.0	150.0
TOTAL EXISTING:	9193.0	8831.0	8398.0	7986.0	7749.0	7700.0	7700.0
NEW GENERATION							
COAL 210 MW		18.0	3265.9	7480.2	12471.1	20419.7	26779.0
COAL 500 MW		14.4	2612.7	5984.1	9976.9	16335.7	21423.2
HYDRO 60 MW		100.0	300.0	500.0	650.0	650.0	650.0
HYDRO 100MW		200.0	400.0	400.0	400.0	400.0	400.0
GAS TUR 60MW		98.8	103.3	107.8	110.3	115.3	115.3
LG HYDRO COST 1		400.0	700.0	700.0	700.0	700.0	700.0
LG HYDRO COST 2		300.0	600.0	700.0	700.0	700.0	700.0
LG HYDRO COST 3					300.0	600.0	600.0
LG HYDRO COST 4							
GAS COMB. CYCLE							
PEAK SHORTFALL							
AVG. SHORTFALL							5285.3
TOTAL NEW:		1131.1	7981.9	15872.1	25308.2	39920.7	56652.7
TOTAL CAPACITY:	9193.0	9962.1	16379.9	23858.1	33057.2	47620.7	64352.7

9E.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	1275.9	1225.7	1165.4	1108.4	1075.3	1062.5	1062.5
COAL FIRED	5626.5	5404.5	5139.8	4887.8	4743.0	4725.0	4725.0
GAS FIRED	161.5	155.6	147.9	140.3	136.0	127.5	127.5
NEW PEAK CAPACITY							
COAL 210 MW		12.6	2286.1	5236.1	8729.8	14293.8	18745.3
COAL 500 MW		10.8	1959.5	4488.1	7482.7	12251.8	16067.4
HYDRO 60 MW		90.0	270.0	450.0	585.0	585.0	585.0
HYDRO 100MW		180.0	360.0	360.0	360.0	360.0	360.0
GAS TUR 60MW		64.2	67.1	70.0	71.7	74.9	74.9
LG HYDRO COST 1		360.0	630.0	630.0	630.0	630.0	630.0
LG HYDRO COST 2		270.0	540.0	630.0	630.0	630.0	630.0
LG HYDRO COST 3					270.0	540.0	540.0
PEAK SHORTFALL							5285.3
PEAK GENERATION:	7063.9	7773.3	12565.8	18000.7	24713.3	35280.5	48832.9
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM N		129.6					
+IMPORT FROM S							
+IMPORT FROM A	29.6	216.0	648.0	648.0	648.0		449.3
+IMPORT FROM W		216.0	216.0				
-EXPORT TO N	135.0					216.0	216.0
-EXPORT TO S	108.0			495.0			
-EXPORT TO A							
-EXPORT TO W	225.0					65.5	
MAX PEAK SUPPLY:	6625.5	8334.9	13429.8	18153.7	25361.3	35431.0	49498.2
-SURPLUS PEAK	1282.2						
-DISTRIBUTION	5343.3	8334.9	13429.8	18153.7	25361.3	35431.0	49498.2

-DIST LOSSES	892.3	1391.9	2242.8	3031.7	4235.3	5917.0	8266.2
+DSM GENER.							
+DECENT. GENER.							
-PEAK DEMAND	4451.0	6943.0	11187.0	15122.0	21126.0	29514.0	41232.0

9E.3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS							
SOLAR .ERMAL							
MICRO 'YDEL							
PHOTOVOLTAIC							
WIND POWER							
TOTAL:							

9E 4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	750.5	721.0	685.5	652.0	126.5	125.0	623.0
+COAL FIRED	2840.5	3245.1	2398.6	2280.9	2213.4	2205.0	2205.0
+GAS FIRED	19.0	18.3	17.4	16.5	16.0	15.0	15.0
NEW SITES							
+COAL 210 MW		11.7	1796.2	4114.1	6859.1	11230.8	14728.4
+COAL 500 MW		9.8	1453.8	3291.3	5487.3	8984.7	11782.7
+HYDRO 60 MW		50.0	150.0	150.0	195.0	195.0	325.0
+HYDRO 100MW		100.0	200.0	120.0	120.0	120.0	200.0
+GAS TUR 60MW		19.8	20.7	21.6	22.1	23.1	23.1
+LG HYDRO COST 1		240.0	420.0	210.0	210.0	210.0	420.0
+LG HYDRO COST 2		180.0	360.0	396.4	210.0	210.0	420.0
+LG HYDRO COST 3							360.0
+PEAK SHORTFALL							
-TOTAL.	3610.0	4595.7	7502.1	11252.8	15459.3	23318.5	31104.2
+IMPORT FROM N		129.6					
+IMPORT FROM S							449.3
+IMPORT FROM A	29.6	216.0	648.0	648.0	648.0		
+IMPORT FROM W		216.0	216.0			216.0	216.0
-EXPORT TO N	135.0			495.0			
-EXPORT TO S	108.0						
-EXPORT TO A						65.5	
-EXPORT TO W	225.0						
-MAX AVG SUPPLY	3171.7	5157.3	8366.1	11405.8	16107.3	23469.0	31769.5
-SURPLUS AVG.					37.7	889.2	

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-DISTRIBUTION:	3171.7	5157.3	8366.1	11405.8	16069.6	22579.8	31769.5
-DIST LOSSES	529.7	861.3	1397.1	1904.8	2683.6	3770.8	5305.5
+DSM GENER.							
+DECENT. GENER.							
-AVG. DEMAND	2642.0	4296.0	6969.0	9501.0	13386.0	18809.0	26464.0

TABLE 9W: WESTERN INDIA
SUPPLY / DEMAND BALANCES

9W.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	2720.0	2613.0	2485.0	2363.0	2293.0	2250.0	2250.0
COAL FIRED	17341.0	16658.0	15841.0	15065.0	14617.0	14000.0	14000.0
GAS FIRED	759.0	729.0	693.0	659.0	640.0	640.0	640.0
NUCLEAR	420.0	403.0	384.0	365.0	354.0	350.0	350.0
TOTAL EXISTING:	21240.0	20403.0	19403.0	18452.0	17904.0	17240.0	17240.0
NEW GENERATION							
COAL 210 MW		1092.0	8548.0	17117.5	29872.9	48190.3	72469.5
COAL 500 MW		1637.9	12822.0	25676.3	44809.4	72285.4	108704.3
NUCLEAR		400.0	1100.0	1100.0	1100.0	1100.0	1100.0
HYDRO 60 MW		100.0	300.0	500.0	650.0	650.0	650.0
HYDRO 100MW		200.0	200.0	200.0	200.0	200.0	200.0
GAS TUR 60MW		4676.0	4676.0	4676.0	4676.0	4676.0	4676.0
LG HYDRO COST 1		260.0	560.0	560.0	560.0	560.0	560.0
LG HYDRO COST 2		200.0	400.0	500.0	500.0	500.0	500.0
LG HYDRO COST 3							
LG HYDRO COST 4							
GAS COMB. CYCLE							
PEAK SHORTFALL							2878.1
AVG. SHORTFALL							
TOTAL NEW:		8565.9	28606.0	50329.8	82368.3	128161.6	191737.8
TOTAL CAPACITY:	21240.0	28968.9	48009.0	68781.8	100272.3	145401.6	208977.8

9W.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	2312.0	2221.1	2112.3	2008.6	1949.1	1912.5	1912.5
COAL FIRED	13005.8	12493.5	11880.8	11298.8	10962.8	10500.0	10500.0
GAS FIRED	645.2	619.7	589.1	560.2	544.0	544.0	544.0
NUCLEAR	315.0	302.3	288.0	273.8	265.5	262.5	262.5
NEW PEAK CAPACITY							
COAL 210 MW		764.4	5983.6	11982.3	20911.1	33733.2	50728.7
COAL 500 MW		1228.4	9616.5	19257.2	33607.1	54214.0	81528.2
NUCLEAR		300.0	825.0	825.0	825.0	825.0	825.0
HYDRO 60 MW		90.0	270.0	450.0	585.0	585.0	585.0
HYDRO 100MW		180.0	180.0	180.0	180.0	180.0	180.0
GAS TUR 60MW		3039.4	3039.4	3039.4	3039.4	3039.4	3039.4
LG HYDRO COST 1		234.0	504.0	504.0	504.0	504.0	504.0
LG HYDRO COST 2		180.0	360.0	450.0	450.0	450.0	450.0
PEAK SHORTFALL							2878.1
PEAK GENERATION:	16277.9	21652.7	35648.5	50829.1	73822.8	106749.6	153937.3
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM N		432.0					
+IMPORT FROM S	294.5			432.0			
+IMPORT FROM E	216.0						
-EXPORT TO N	. 440 6		450.0	450.0	407.6	450.0	450.0
-EXPORT TO S		202.6					
-EXPORT TO E		225.0	225.0			225.0	225.0
MAX PEAK SUPPLY:	16347.8	21657.0	34973.5	50811.1	73415.2	106074.6	153262.3
-SURPLUS PEAK							

-DISTRIBUTION	16347.8	21657.0	34973.5	50811.3	73415.2	106074.6	153262.3
-DIST LOSSES	2762.8	3660.0	5910.5	8587.1	12407.2	17926.6	25901.3
+DSM GENER.							
+DECENT. GENER.							
-PEAK DEMAND	13585.0	17997.0	29063.0	42224.0	61008.0	88148.0	127361.0

9W.3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
B1 REP GLS							
B2 REP FTL							
B3 EFF FRIDGE							
B4 EFF FANS							
B5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS							
SOLAR THERMAL							
MICRO HYDEL							
PHOTOVOLTAIC							
WIND POWER							
TOTAL:							

9W.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	1224.0	1175.8	1118.3	1063.3	1031.8	225.0	225.0
+COAL FIRED	8687.1	9994.8	7920.5	7532.5	7308.5	7000.0	7000.0
+GAS FIRED	455.4	437.4	415.8	395.4	384.0	384.0	384.0
+NUCLEAR	252.0	241.8	230.4	182.5	177.0	175.0	175.0
NEW SITES							
+COAL 210 MW		709.8	4701.4	9416.6	16430.1	26504.6	39858.7
+COAL 500 MW		1113.8	8719.0	15030.0	24645.2	39757.0	59787.3
+NUCLEAR		260.0	524.2	440.0	440.0	440.0	440.0
+HYDRO 60 MW		45.0	135.0	225.0	292.5	195.0	195.0
+HYDRO 100MW		90.0	90.0	90.0	90.0	60.0	60.0
+GAS TUR 60MW		935.2	935.2	935.2	935.2	935.2	935.2
+LG HYDRO COST 1		156.0	336.0	336.0	336.0	168.0	168.0
+LG HYDRO COST 2		120.0	240.0	300.0	300.0	150.0	150.0
+PEAK SHORTFALL							
=TOTAL:	10618.5	15279.6	25365.7	35944.6	52370.3	75993.8	109377.8
+IMPORT FROM N		432.0					
+IMPORT FROM S	294.5			432.0			
+IMPORT FROM E	216.0						
-EXPORT TO N	440.6		450.0	450.0	407.6	450.0	450.0
-EXPORT TO S		202.6					
-EXPORT TO E		225.0	225.0			225.0	225.0
=MAX AVG. SUPPLY:	10688.3	15284.0	24690.7	35926.6	51962.7	75318.8	108702.8
-SURPLUS AVG.						162.4	
=DISTRIBUTION:	10688.3	15284.0	24690.7	35926.6	51962.7	75156.4	108702.8

DIST LOSSES	1806.3	2583.0	4172.7	6071.6	8781.7	12701.4	18370.8
DSM GENER.							
DECENT. GENER.							
AVG. DEMAND	8882.0	12701.0	20518.0	29155.0	43181.0	62455.0	90332.0

TABLE 95: SOUTHERN INDIA
SUPPLY / DEMAND BALANCES

95.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	8290.0	7963.0	7573.0	7202.0	6988.0	6900.0	6900.0
COAL FIRED	8422.0	8090.0	7694.0	7317.0	7099.0	7000.0	7000.0
GAS FIRED	66.0	63.0	60.0	57.0	56.0	55.0	55.0
NUCLEAR	470.0	451.0	429.0	408.0	396.0	390.0	390.0
TOTAL EXISTING:	17248.0	16567.0	15756.0	14984.0	14539.0	14345.0	14345.0
NEW GENERATION							
COAL 210 MW			2795.0	6329.2	11334.4	18482.2	26753.4
COAL 500 MW			6987.4	15823.0	28336.0	46205.5	66883.4
NUCLEAR		300.0	1000.0	1000.0	1000.0	1000.0	1000.0
HYDRO 60 MW		120.0	320.0	450.0	450.0	450.0	450.0
HYDRO 100MW		250.0	500.0	500.0	500.0	500.0	500.0
GAS TUR 60MW		3441.4	3441.4	3711.4	3711.4	3711.4	3711.4
LG HYDRO COST 1		200.0	400.0	600.0	600.0	600.0	600.0
LG HYDRO COST 2		200.0	400.0	600.0	600.0	600.0	600.0
LG HYDRO COST 3							
LG HYDRO COST 4							
GAS COMB. CYCLE							
PEAK SHORTFALL							4809.4
AVG. SHORTFALL							
TOTAL NEW:		4511.4	15843.8	29013.7	46531.8	71549.1	105307.6
TOTAL CAPACITY:	17248.0	21078.4	31599.8	43997.7	61070.8	85894.1	119652.6

95.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	6632.0	6370.4	6058.4	5761.6	5590.4	5520.0	5520.0
COAL FIRED	5895.4	5663.0	5385.8	5121.9	4969.3	4900.0	4900.0
GAS FIRED	56.1	53.6	51.0	48.5	47.6	46.8	46.8
NUCLEAR	352.5	338.3	321.8	306.0	297.0	292.5	292.5
NEW PEAK CAPACITY							
COAL 210 MW			1956.5	4430.4	7934.1	12937.5	18727.4
COAL 500 MW			5240.6	11867.3	21252.0	34654.1	50162.6
NUCLEAR		225.0	750.0	750.0	750.0	750.0	750.0
HYDRO 60 MW		108.0	288.0	405.0	405.0	405.0	405.0
HYDRO 100MW		225.0	450.0	450.0	450.0	450.0	450.0
GAS TUR 60MW		2236.9	2236.9	2412.4	2412.4	2412.4	2412.4
LG HYDRO COST 1		180.0	360.0	540.0	540.0	540.0	540.0
LG HYDRO COST 2		180.0	360.0	540.0	540.0	540.0	540.0
PEAK SHORTFALL							4809.4
PEAK GENERATION:	12936.0	15580.1	23458.9	32633.1	45187.8	63448.4	89556.0
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM E	103.7						
+IMPORT FROM W		194.5					
-EXPORT TO E							468.0
-EXPORT TO W	306.8			450.0			
MAX PEAK SUPPLY:	12732.9	15774.6	23458.9	32183.1	45187.8	63448.4	89088.0
-SURPLUS PEAK	365.5						
-DISTRIBUTION	12367.4	15774.6	23458.9	32183.1	45187.8	63448.4	89088.0

-DIST LOSSES	1830.4	2334.6	3471.9	4763.1	6687.8	9390.4	13185.0
+DSM GENER.							
+DECENT. GENER.							
-PEAK DEMAND	10537.0	13440.0	19987.0	27420.0	38500.0	54058.0	75903.0

95.3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS							
SOLAR THERMAL							
MICRO HYDEL							
PHOTOVOLTAIC							
WIND POWER							
TOTAL:							

95.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	3730.5	3583.4	3407.9	3088.0	2795.2	2760.0	2760.0
+COAL FIRED	4246.1	4854.0	3847.0	3658.5	3549.5	3500.0	3500.0
+GAS FIRED	39.6	37.8	36.0	34.2	33.6	33.0	33.0
+NUCLEAR	282.0	270.6	257.4	204.0	198.0	195.0	195.0
NEW SITES							
+COAL 210 MW			1537.2	3481.1	6233.9	10165.2	14714.3
+COAL 500 MW			3952.6	8702.7	15584.8	25413.0	36785.9
+NUCLEAR		195.0	650.0	400.0	400.0	400.0	400.0
+HYDRO 60 MW		54.0	144.0	202.5	135.0	135.0	135.0
+HYDRO 100MW		112.5	225.0	225.0	150.0	150.0	150.0
+GAS TUR 60MW		688.3	688.3	742.3	742.3	742.3	742.3
+LG HYDRO COST 1		120.0	240.0	360.0	180.0	180.0	180.0
+LG HYDRO COST 2		120.0	240.0	360.0	180.0	180.0	180.0
+PEAK SHORTFALL							
-TOTAL:	8298.2	10035.5	15225.4	21458.2	30182.3	43853.5	59775.5
+IMPORT FROM E	103.7						
+IMPORT FROM W		194.5					
-EXPORT TO E							468.0
-EXPORT TO W	306.8			450.0			
-MAX AVG. SUPPLY:	8095.1	10230.0	15225.4	21008.2	30182.3	43853.5	59307.5
-SURPLUS AVG.					491.0	1889.9	
-DISTRIBUTION:	8095.1	10230.0	15225.4	21008.2	29691.3	41963.6	59307.5
-DIST LOSSES	1198.1	1514.0	2253.4	3109.2	4394.3	6210.6	8777.5

+DSM GENER.							
+DECENT. GENER.							
-AVG. DEMAND	6897.0	8716.0	12972.0	17899.0	25297.0	35753.0	50530.0

TABLE 10: INTERREGIONAL TRANSMISSION

10.1A TRANSMISSION FROM NORTH TO EAST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	150.0	150.0	150.0	150.0	150.0	150.0	150.0
NEW CAPACITY			400.0	400.0	400.0	400.0	400.0
TOTAL:							
PEAK CAPACITY	150.0	150.0	550.0	550.0	550.0	550.0	550.0
AVG. CAPACITY	135.0	135.0	495.0	495.0	495.0	495.0	495.0
AVG. UTILIZ.		135.0					

10.1B TRANSMISSION FROM EAST TO NORTH

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	150.0	150.0	150.0	150.0	150.0	150.0	150.0
NEW CAPACITY			400.0	400.0	400.0	400.0	400.0
TOTAL:							
PEAK CAPACITY	150.0	150.0	550.0	550.0	550.0	550.0	550.0
AVG. CAPACITY	135.0	135.0	495.0	495.0	495.0	495.0	495.0
AVG. UTILIZ.	135.0			495.0			

10.2A TRANSMISSION FROM NORTH TO WEST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
NEW CAPACITY							
TOTAL:							
PEAK CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
AVG. CAPACITY	450.0	450.0	450.0	450.0	450.0	450.0	450.0
AVG. UTILIZ.		450.0					

10 2B TRANSMISSION FROM WEST TO NORTH

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	500.0	500.0	500.0	500.0	500.0	500 0	500.0
NEW CAPACITY							
TOTAL:							
PEAK CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
AVG. CAPACITY	450.0	450.0	450.0	450.0	450.0	450.0	450.0
AVG. UTILIZ.	440.6		450.0	450.0	407.6	450 0	450.0

10 3A TRANSMISSION FROM SOUTH TO EAST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	120.0	120.0	120.0	120.0	120.0	120.0	120.0
NEW CAPACITY			400 0	400.0	400.0	400.0	400.0
TOTAL:							
PEAK CAPACITY	120.0	120.0	520 0	520.0	520.0	520.0	520.0

	1991	1996	2001	2006	2011	2016	2021
AVG. CAPACITY	108.0	108.0	468.0	468.0	468.0	468.0	468.0
AVG. UTILIZ.							468.0

10.3B TRANSMISSION FROM EAST TO SOUTH

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	120.0	120.0	120.0	120.0	120.0	120.0	120.0
NEW CAPACITY			400.0	400.0	400.0	400.0	400.0
TOTAL: PEAK CAPACITY	120.0	120.0	520.0	520.0	520.0	520.0	520.0
AVG. CAPACITY	108.0	108.0	468.0	468.0	468.0	468.0	468.0
AVG. UTILIZ.	108.0						

10.4A TRANSMISSION FROM SOUTH TO WEST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
NEW CAPACITY							
TOTAL: PEAK CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
AVG. CAPACITY	450.0	450.0	450.0	450.0	450.0	450.0	450.0
AVG. UTILIZ.	306.8			450.0			

10.4B TRANSMISSION FROM WEST TO SOUTH

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
NEW CAPACITY							
TOTAL: PEAK CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
AVG. CAPACITY	450.0	450.0	450.0	450.0	450.0	450.0	450.0
AVG. UTILIZ.		202.6					

10.5A TRANSMISSION FROM N.E. TO EAST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
NEW CAPACITY			500.0	500.0	500.0	500.0	500.0
TOTAL: PEAK CAPACITY	250.0	250.0	750.0	750.0	750.0	750.0	750.0
AVG. CAPACITY	225.0	225.0	675.0	675.0	675.0	675.0	675.0
AVG. UTILIZ.	30.9	225.0	675.0	675.0	675.0		

10.5B TRANSMISSION FROM EAST TO N.E.

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
NEW CAPACITY			500.0	500.0	500.0	500.0	500.0
TOTAL: PEAK CAPACITY	250.0	250.0	750.0	750.0	750.0	750.0	750.0
AVG. CAPACITY	225.0	225.0	675.0	675.0	675.0	675.0	675.0
AVG. UTILIZ.						65.5	

10.6A TRANSMISSION FROM WEST TO EAST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	250.0	250.0	250.0	250.0	250.0	250 0	250.0
NEW CAPACITY							
TOTAL: PEAK CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
AVG. CAPACITY	225.0	225.0	225.0	225.0	225.0	225.0	225.0
AVG. UTILIZ.		225.0	225.0			225.0	225.0

10.6B TRANSMISSION FROM EAST TO WEST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	250.0	250.0	250.0	250.0	250 0	250 0	250.0

NEW CAPACITY							
TOTAL:							
PEAK CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
AVG. CAPACITY	225.0	225.0	225.0	225.0	225.0	225.0	225.0
AVG. UTILIZ.	225.0						

TABLE 14: FUEL COSTS

HYDROPOTENTIAL IN RUPEES/MW

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA AVG:							

COAL DOM A1 IN RUPEES/TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	320.0	320.0	320.0	320.0	320.0	320.0	320.0
NORTHERN INDIA	280.0	280.0	280.0	280.0	280.0	280.0	280.0
EASTERN INDIA	320.0	320.0	320.0	320.0	320.0	320.0	320.0
WESTERN INDIA	280.0	280.0	280.0	280.0	280.0	280.0	280.0
SOUTHERN INDIA	360.0	360.0	360.0	360.0	360.0	360.0	360.0
INDIA AVG:	312.0	312.0	312.0	312.0	312.0	312.0	312.0

COAL IMPORT 1 IN RUPEES/TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA AVG:							

NATURAL GAS IN RUPEES/000m3

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	1820.0	1820.0	1820.0	1820.0	1820.0	1820.0	1820.0
NORTHERN INDIA	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0
EASTERN INDIA	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0
WESTERN INDIA	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0
SOUTHERN INDIA	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0
INDIA AVG:	2252.0	2252.0	2252.0	2252.0	2252.0	2252.0	2252.0

FUEL OIL IN RUPEES/m^3

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
NORTHERN INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
EASTERN INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
WESTERN INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
SOUTHERN INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
INDIA AVG:	450.0	450.0	450.0	450.0	450.0	450.0	450.0

NUCLEAR FUEL IN RUPEES/kg U

REGION	1991	1996	2001	2006	2011	2016	2021

NORTH-EAST INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
NORTHERN INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
EASTERN INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
WESTERN INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
SOUTHERN INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
INDIA AVG:	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0

TESTING FUEL IN RUPEES/UNITS

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
NORTHERN INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
EASTERN INDIA	997.0	997.0	997.0	997.0	997.0	997.0	997.0
WESTERN INDIA	998.0	998.0	998.0	998.0	998.0	998.0	998.0
SOUTHERN INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
INDIA AVG:	998.4	998.4	998.4	998.4	998.4	998.4	998.4

BACKSTOP FUEL IN RUPEES/UNITS

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
NORTHERN INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
EASTERN INDIA	997.0	997.0	997.0	997.0	997.0	997.0	997.0
WESTERN INDIA	998.0	998.0	998.0	998.0	998.0	998.0	998.0
SOUTHERN INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
INDIA AVG:	998.4	998.4	998.4	998.4	998.4	998.4	998.4

INDIAN ELITE

The Indian Electric
Inter-regional Transfer
and Emissions Model

Ver. 2.1 / Dec. 94

Developed by:
Ken Melax and Sam Wong

Alberta
Research
Council

Developed for: Canadian Energy Research Institute (CERI)

MODEL SOLUTION REPORT

For model run on: 15 DEC 94

With solution status: OPTM

OPTIMAL MINIMIZED SOLUTION IS: 549614 RUPEES CRORES

MODEL SIZE ROWS: 2903
COLUMNS: 3797

SCENARIO: REFERENCE SCENARIO
WITH RENEWABLES
NO DSM, NO CO-GEN, NO CCT

IMPORTANT CONSTRAINTS:

MAXIMUM CAPITAL INVESTMENT ALLOWED (RUPEE CRORES/TIME PERIOD)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	50000.0	80000.0	147730.0	197700.0	264560.0	354050.0	473800.0
ACTUAL INVESTMENT		80000.0	147730.0	197700.0	264560.0	316051.1	340617.0

MAXIMUM HYDROPOWER GENERATION CAPACITY (MW)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	50000.0	50000.0	50000.0	50000.0	60000.0	70000.0	80000.0
ACTUAL CAPACITY	19189.0	27168.4	35261.4	46860.0	59415.0	70000.0	76460.0

MAXIMUM GAS AVAILABLE IN NORTH, WEST AND SOUTH (MILLION M3)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	4200.0	9680.0	12000.0	12000.0	12000.0	12000.0	12000.0
ACTUAL USAGE	3170.9	3044.8	12000.0	12000.0	12000.0	12000.0	12000.0

MAXIMUM GAS AVAILABLE IN NORTH EAST (MILLION M3)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	2020.0	2020.0	2600.0	2600.0	2600.0	2600.0	2600.0
ACTUAL USAGE	101.4	97.5	457.5	1616.2	2600.0	2600.0	2600.0

MAXIMUM GAS AVAILABLE IN EAST (MILLION M3)

	1991	1996	2001	2006	2011	2016	2021
UPPER LIMIT	100.0	100.0	100.0	100.0	100.0	100.0	100.0
ACTUAL USAGE	49.9	48.1	100.0	100.0	100.0	100.0	100.0

TABLE 1: ELECTRICITY DEMAND

1.1 NORTH-EAST INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	566.0	1247.0	2913.0	4415.0	7065.0	11255.0	17930.0
AVERAGE DEMAND	285.0	610.0	1467.0	2327.0	3828.0	6297.0	10359.0

1.2 NORTHERN INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	14533.0	17692.0	27330.0	36551.0	51241.0	71837.0	100709.0
AVERAGE DEMAND	8023.0	10750.0	16680.0	22530.0	31870.0	45090.0	63800.0

1.3 EASTERN INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	4451.0	6943.0	11187.0	15122.0	21126 0	29514.0	41232.0
AVERAGE DEMAND	2642.0	4296.0	6969.0	9501.0	13386.0	18809.0	26464.0

1.4 WESTERN INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	13585.0	17997.0	29063.0	42224.0	61008.0	88148.0	127361.0
AVERAGE DEMAND	8882.0	12701.0	20518.0	29855.0	43181.0	62455.0	90332.0

1.5 SOUTHERN INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	10537.0	13440.0	19987.0	27420.0	38500.0	54058.0	75903.0
AVERAGE DEMAND	6897.0	8716.0	12972.0	17899.0	25297.0	35753.0	50530.0

1.6 TOTAL INDIA

	1991	1996	2001	2006	2011	2016	2021
PEAK DEMAND	43672.0	57319.0	90480.0	125732.0	178940 0	254812.0	363135.0
AVERAGE DEMAND	26729.0	37073.0	58606.0	82112.0	117562.0	164404.0	241485.0

TABLE 2: ELECTRICITY GENERATION CAPACITY

2.1 INDIAN INSTALLED ELECTRIC GENERATION CAPACITY

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	1052.0	2611.0	4855.0	9554.6	16557.0	23145.6	29221.5
NORTHERN INDIA	20337.0	25741.1	41391.7	55136.8	78603.4	111070.6	155773.0
EASTERN INDIA	9193.0	9952.3	14424.3	17254.9	24645.6	35932.5	55636.1
WESTERN INDIA	21240.0	29248.4	47302.2	67272.0	95866.7	137206.7	194547.7
SOUTHERN INDIA	17248.0	20263.1	29796.0	40511.4	54940.2	77246.0	108562.5
INDIA TOTAL:	69070.0	87815.8	137769.1	189729.7	270613.0	384601.4	543740.8
% RESERVE MARGIN	36.8	34.7	34.3	33.7	33.9	33.7	33.2

2.2 INDIAN PEAK GENERATION CAPACITY

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	806.3	2214.9	4067.7	8285.2	14432.6	20364.5	25644.4
NORTHERN INDIA	17797.2	22403.9	33845.8	45373.6	63806.6	90128.8	126468.4
EASTERN INDIA	7063.9	7773.3	12038.5	14862.8	20468.7	29592.2	45336.5
WESTERN INDIA	16277.9	22232.8	35359.7	50946.1	73287.5	105352.6	152395.9
SOUTHERN INDIA	12936.0	15278.1	23338.9	31769.1	44011.7	61978.3	87323.9
INDIA TOTAL:	54881.2	69903.0	108650.5	151236.8	216007.3	307416.3	437169.1

2.3 INDIAN AVERAGE GENERATION

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	383.6	877.8	2278.1	5281.0	9246.5	13140.9	16274.3
NORTHERN INDIA	9577.5	13638.8	20398.8	27670.3	39348.3	56357.3	79866.2
EASTERN INDIA	3610.0	4595.7	6974.8	8114.9	11177.0	16741.1	27607.8
WESTERN INDIA	10618.5	15859.7	25076.9	36061.6	51835.1	74434.4	107836.3
SOUTHERN INDIA	8298.2	9733.5	15105.3	20594.2	28515.3	40493.5	57543.4
INDIA TOTAL:	32487.7	44705.5	69834.0	97722.0	140122.2	201167.3	289128.1

2.4 INSTALLED GENERATION CAPACITY BY FUEL TYPE

TYPE	1991	1996	2001	2006	2011	2016	2021
COAL	45509.0	54948.4	67327.9	91502.2	125421.3	161309.2	191429.0
NUCLEAR	1785.0	3214.0	6131.0	12051.0	18004.0	25490.0	28490.0
GAS	2587.0	2485.0	20483.3	21010.8	22027.7	22024.3	22777.8
HYDRO	19189.0	27168.4	35261.4	46860.0	59415.0	70000.0	76460.0
OTHER							
SHORTFALL			8565.5	18305.7	45745.0	105777.9	224584.0
INDIA TOTAL:	69070.0	87815.8	137769.1	189729.7	270613.0	384601.4	543740.8
% HYDRO (EX SF)	27.8	30.9	27.3	27.3	26.4	25.1	24.0

2.5 DECENTRALIZED GENERATION

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA		150.0	420.0	630.0	840.0	1050.0	1260.0
NORTHERN INDIA		100.0	440.0	660.0	880.0	1100.0	1320.0
EASTERN INDIA			120.0	180.0	240.0	300 0	360.0
WESTERN INDIA		150.0	600.0	900.0	1200.0	1500.0	1800.0
SOUTHERN INDIA		100.0	1620.0	2430.0	3240.0	4050.0	4860.0
INDIA TOTAL:		500.0	3200.0	4800.0	6400.0	8000.0	9600.0

2.6 DEMAND SIDE MANAGEMENT

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA TOTAL:							

2.7 CLEAN COAL TECHNOLOGIES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA TOTAL:							

TABLE 3: FINANCIAL SUMMARY

3.1 REAL COSTS IN RUPEE CRORES

YEAR	FUEL & VARIABLE	FIXED & CAPITAL	TOTAL
1991	63913		63913
1996	85106	66582	151688
2001	149509	164290	313799
2006	212428	261341	473769
2011	336657	410225	746882
2016	542042	571007	1113049
2021	884286	720366	1604652
TOT	2273941	2193811	4467752

3.2 DISCOUNTED COSTS IN RUPEE CRORES

DISCOUNT RATE - 12%

YEAR	FUEL & VARIABLE	FIXED & CAPITAL	TOTAL
1991	63913		63913
1996	44913	35137	80051
2001	41638	45755	87393
2006	31221	38410	69632
2011	26112	31818	57930
2016	22187	23372	45559
2021	19101	15561	34662
TOT	249086	190054	439141
	COST OF SHORTFALL:		110474
	OPTIMAL SOLUTION:		549614

3.3 CAPITAL INVESTMENT IN GENERATION FACILITIES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA		3460	4154	14579	25461	27417	24236
NORTHERN INDIA		15641	26100	35407	25963	22442	7393
EASTERN INDIA		2706	3480	3994	18036	2785	
WESTERN INDIA		20100	30296	42261	56743	80875	69464
SOUTHERN INDIA		8623	15606	25192	23268	19136	5360
INDIA TOTAL:		50530	79635	121434	149470	152656	106453

3.4 CAPITAL INVESTMENT IN DISTRIBUTION FACILITIES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA		779	2431	2500	4611	7797	13042
NORTHERN INDIA		8788	19490	19342	31064	44095	62534
EASTERN INDIA		4935	8421	8028	12348	17260	24387
WESTERN INDIA		10860	24518	29503	42272	61311	88849
SOUTHERN INDIA		4108	11895	14600	22315	31862	45353
INDIA TOTAL:		29470	66755	73974	112609	162325	234164

3.5 CAPITAL INVESTMENT IN INTRA-REGIONAL TRANSMISSION

LINE	1991	1996	2001	2006	2011	2016	2021
NORTH TO EAST			400				
EAST TO NORTH							
SOUTH TO EAST							
EAST TO SOUTH			400				
N.E. TO EAST			500	2292	2480		
EAST TO N.E.			40			1070	
INDIA TOTAL:			1340	2292	2480	1070	

TABLE 4: UNIT COST SUMMARY

REAL COSTS IN 1991 (PAISE/KWH)

GENERATOR	REGION	ANNUAL CAPITAL P/KWH	FIXED COST P/KWH	VARIABLE COST P/KWH	'91 FUEL COST P/KWH	TOTAL COST P/KWH
EXISTING GENERATION						
HYDPO	N.E.			4.00		4.00
HYDRO	NORTH			4.00		4.00
HYDRO	FAST			4.00		4.00
HYDRO	WEST			4.00		4.00
HYDRO	SOUTH			4.00		4.00
COAL FIRED	N.E.			10.00	19.43	29.43
COAL FIRED	NORTH			10.00	19.82	29.82
COAL FIRED	EAST			10.00	22.62	32.62
COAL FIRED	WEST			10.00	20.10	30.10
COAL FIRED	SOUTH			10.00	26.51	36.51
GAS FIRED	N.E.			7.30	54.60	61.90
GAS FIRED	NORTH			7.30	70.80	78.10
GAS FIRED	EAST			7.30	70.80	78.10
GAS FIRED	WEST			7.30	70.80	78.10
GAS FIRED	SOUTH			7.30	70.80	78.10
NUCLEAR	NORTH			10.00	18.26	28.26
NUCLEAR	WEST			10.00	18.26	28.26
NUCLEAR	SOUTH			10.00	18.26	28.26

NEW GENERATION						
COAL 210 MW	N.E.	55.98	10.98	11.50	20.38	98.84
COAL 210 MW	NORTH	55.98	10.98	11.50	17.86	96.32
COAL 210 MW	EAST	55.98	10.98	11.50	20.38	98.84
COAL 210 MW	WEST	55.98	10.98	11.50	17.86	96.32
COAL 210 MW	SOUTH	55.98	10.98	11.50	22.90	101.36
COAL 500 MW	N.E.	42.81	8.39	11.50	19.10	81.81
COAL 500 MW	NORTH	42.81	8.39	11.50	16.74	79.45
COAL 500 MW	EAST	42.81	8.39	11.50	19.10	81.81
COAL 500 MW	WEST	42.81	8.39	11.50	16.74	79.45
COAL 500 MW	SOUTH	42.81	8.39	11.50	21.46	84.17
NUCLEAR	NORTH	68.74	9.66	10.00	18.26	106.66
NUCLEAR	WEST	68.74	9.66	10.00	18.26	106.66
NUCLEAR	SOUTH	68.74	9.66	10.00	18.26	106.66
HYDRO 60 MW	N.E.	61.44	12.56	4.00		77.99
HYDRO 60 MW	NORTH	61.44	12.56	4.00		77.99
HYDRO 60 MW	EAST	61.44	12.56	4.00		77.99
HYDRO 60 MW	WEST	68.26	13.95	4.00		86.22
HYDRO 60 MW	SOUTH	68.26	13.95	4.00		86.22
HYDRO 100MW	N.E.	55.85	11.42	4.00		71.27
HYDRO 100MW	NORTH	55.85	11.42	4.00		71.27
HYDRO 100MW	EAST	55.85	11.42	4.00		71.27
HYDRO 100MW	WEST	62.06	12.68	4.00		78.74
HYDRO 100MW	SOUTH	62.06	12.68	4.00		78.74
GAS TUR 60MW	N.E.	58.22	11.42	4.00	54.60	128.23
GAS TUR 60MW	NORT	58.22	11.42	4.00	70.80	144.43
GAS TUR 60MW	EAST	58.22	11.42	4.00	70.80	144.43
GAS TUR 60MW	WEST	58.22	11.42	4.00	70.80	144.43
GAS TUR 60MW	SOUT	58.22	11.42	4.00	70.80	144.43
LG HYDRO COST 1	N.E.	51.20	8.56	4.00		63.76
LG HYDRO COST 1	NORTH	51.20	8.56	4.00		63.76
LG HYDRO COST 1	EAST	51.20	8.56	4.00		63.76
LG HYDRO COST 1	WEST	51.20	8.56	4.00		63.76
LG HYDRO COST 1	SOUTH	51.20	8.56	4.00		63.76
LG HYDRO COST 2	N.E.	72.14	8.56	4.00		84.70
LG HYDRO COST 2	NORTH	72.14	8.56	4.00		84.70
LG HYDRO COST 2	EAST	72.14	8.56	4.00		84.70
LG HYDRO COST 2	WEST	72.14	8.56	4.00		84.70
LG HYDRO COST 2	SOUTH	72.14	8.56	4.00		84.70
LG HYDRO COST 3	N.E.	107.05	8.56	4.00		119.61
LG HYDRO COST 3	NORTH	107.05	8.56	4.00		119.61
LG HYDRO COST 3	EAST	107.05	8.56	4.00		119.61
LG HYDRO COST 3	WEST	107.05	8.56	4.00		119.61
LG HYDRO COST 3	SOUTH	107.05	8.56	4.00		119.61
LG HYDRO COST 4	N.E.	144.29	8.56	4.00		156.85
LG HYDRO COST 4	NORTH	144.29	8.56	4.00		156.85
LG HYDRO COST 4	EAST	144.29	8.56	4.00		156.85
LG HYDRO COST 4	WEST	144.29	8.56	4.00		156.85
LG HYDRO COST 4	SOUTH	144.29	8.56	4.00		156.85
GAS COMB. CYCLE	N.E.	35.83	4.18	8.50	54.60	103.10
GAS COMB. CYCLE	NORTH	35.83	4.18	8.50	70.80	119.30
GAS COMB. CYCLE	EAST	35.83	4.18	8.50	70.80	119.30
GAS COMB. CYCLE	WEST	35.83	4.18	8.50	70.80	119.30
GAS COMB. CYCLE	SOUTH	35.83	4.18	8.50	70.80	119.30
PEAK SHORTFALL	N.E.	291.10		90.00		381.10
PEAK SHORTFALL	NORTH	291.10		90.00		381.10
PEAK SHORTFALL	EAST	291.10		90.00		381.10
PEAK SHORTFALL	WEST	291.10		90.00		381.10
PEAK SHORTFALL	SOUTH	291.10		90.00		381.10
AVG. SHORTFALL	N.E.	121.29	95.13	90.00		306.42
AVG. SHORTFALL	NORTH	121.29	95.13	90.00		306.42
AVG. SHORTFALL	EAST	121.29	95.13	90.00		306.42
AVG. SHORTFALL	WEST	121.29	95.13	90.00		306.42
AVG. SHORTFALL	SOUTH	121.29	95.13	90.00		306.42

TABLE 5: INSTALLED CAPACITY (IN MW)

TYPE		1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION								
HYDRO	A	426.0	409.0	389.0	370.0	359.0	350.0	350.0
HYDRO	N	6252.0	6009.0	5711.0	5431.0	5270.0	5200.0	5200.0
HYDRO	E	1501.0	1442.0	1371.0	1304.0	1265.0	1250.0	1250.0
HYDRO	W	2720.0	2613.0	2485.0	2363.0	2293.0	2250.0	2250.0
HYDRO	S	8290.0	7963.0	7573.0	7202.0	6988.0	6900.0	6900.0
COAL FIRED	A	240.0	231.0	219.0	208.0	202.0	200.0	200.0
COAL FIRED	N	12004.0	11531.0	11077.0	10428.0	10119.0	10000.0	10000.0
COAL FIRED	E	7502.0	7206.0	6853.0	6517.0	6324.0	6300.0	6300.0
COAL FIRED	W	17341.0	16658.0	15841.0	15065.0	14617.0	14000.0	14000.0
COAL FIRED	S	8422.0	8090.0	7694.0	7317.0	7099.0	7000.0	7000.0
GAS FIRED	A	386.0	371.0	353.0	335.0	325.0	320.0	320.0
GAS FIRED	N	1186.0	1139.0	1083.0	1030.0	1000.0	1000.0	1000.0
GAS FIRED	E	190.0	183.0	174.0	165.0	160.0	150.0	150.0
GAS FIRED	W	759.0	729.0	693.0	659.0	640.0	640.0	640.0
GAS FIRED	S	66.0	63.0	60.0	57.0	56.0	55.0	55.0
NUCLEAR	N	895.0	860.0	818.0	778.0	754.0	750.0	750.0
NUCLEAR	W	420.0	403.0	384.0	365.0	354.0	350.0	350.0
NUCLEAR	S	470.0	451.0	429.0	408.0	396.0	390.0	390.0
TOTAL EXISTING:		69070.0	66351.0	63207.0	60002.0	58221.0	57105.0	57105.0

TYPE		1991	1996	2001	2006	2011	2016	2021
NEW GENERATION								
COAL 210 MW	A							
COAL 210 MW	N		733.1	932.6	3786.0	4204.0	4204.0	4204.0
COAL 210 MW	E		67.4	449.5	449.5	3977.1	3977.1	3977.1
COAL 210 MW	W		3034.1	6345.8	12309.7	20926.6	33951.1	45999.1
COAL 210 MW	S		693.2	2163.3	4201.4	6079.8	7276.2	7276.2
COAL 500 MW	A							
COAL 500 MW	N		366.6	466.3	1893.0	2102.0	2102.0	2102.0
COAL 500 MW	E		53.9	359.6	359.6	3181.7	3181.7	3181.7
COAL 500 MW	W		4551.2	9518.8	18464.6	31389.8	50926.7	68998.6
COAL 500 MW	S		1732.9	5408.2	10503.5	15199.4	18190.4	18190.4
NUCLEAR	N		500.0	1500.0	3500.0	5500.0	8000.0	9000.0
NUCLEAR	W		500.0	1500.0	3500.0	5500.0	8000.0	9000.0
NUCLEAR	S		500.0	1500.0	3500.0	5500.0	8000.0	9000.0
HYDRO 60 MW	A		300.0	600.0	900.0	1200.0	1500.0	1800.0
HYDRO 60 MW	N		440.0	1190.0	1940.0	2690.0	3300.0	3300.0
HYDRO 60 MW	E		100.0	300.0	500.0	650.0	650.0	650.0
HYDRO 60 MW	W		100.0	300.0	500.0	650.0	650.0	650.0
HYDRO 60 MW	S		120.0	320.0	450.0	450.0	450.0	450.0
HYDRO 100MW	A		300.0	600.0	900.0	1200.0	1500.0	1800.0
HYDRO 100MW	N		900.0	2500.0	4100.0	5300.0	5300.0	5300.0
HYDRO 100MW	E		200.0	400.0	400.0	400.0	400.0	400.0
HYDRO 100MW	W		200.0	200.0	200.0	200.0	200.0	200.0
HYDRO 100MW	S		250.0	500.0	500.0	500.0	500.0	500.0
GAS TUR 60MW	A			694.0	694.0	1253.4	1253.4	2006.9
GAS TUR 60MW	N			9651.4	10121.4	10271.4	10271.4	10271.4
GAS TUR 60MW	E			103.3	107.8	110.3	115.3	115.3
GAS TUR 60MW	W			7471.6	7471.6	7471.6	7471.6	7471.6
GAS TUR 60MW	S						3.0	3.0
LG HYDRO COST 1A			1000.0	2000.0	3000.0	4000.0	5000.0	5500.0
LG HYDRO COST 1N			2000.0	4000.0	4000.0	4000.0	4000.0	4000.0
LG HYDRO COST 1E			400.0	700.0	700.0	700.0	700.0	700.0
LG HYDRO COST 1W			260.0	560.0	560.0	560.0	560.0	560.0
LG HYDRO COST 1S			200.0	400.0	600.0	600.0	600.0	600.0
LG HYDRO COST 2A					1500.0	3000.0	4500.0	5500.0
LG HYDRO COST 2N			1000.0	2000.0	3000.0	4000.0	4000.0	4000.0
LG HYDRO COST 2E			300.0	400.0	700.0	700.0	700.0	700.0
LG HYDRO COST 2W			200.0	300.0	500.0	500.0	500.0	500.0
LG HYDRO COST 2S			200.0	200.0	400.0	600.0	600.0	600.0
LG HYDRO COST 3A					1277.6	2777.6	4277.6	5500.0
LG HYDRO COST 3N			262.4	262.4	1262.4	2262.4	3762.4	4000.0
LG HYDRO COST 3E					300.0	600.0	800.0	800.0
LG HYDRO COST 3W					300.0	600.0	600.0	600.0
LG HYDRO COST 3S					200.0	400.0	600.0	800.0
LG HYDRO COST 4A						1500.0	3500.0	5500.0
LG HYDRO COST 4N					1000.0	2000.0	3000.0	3500.0
LG HYDRO COST 4E					200.0	500.0	800 0	800.0
LG HYDRO COST 4W					100.0	300 0	500 0	500.0
LG HYDRO COST 4S					200.0	400 0	600 0	800 0
GAS COMB. CYCLEA					370.0	740 0	744 6	744 6
GAS COMB. CYCLEN								
GAS COMB. CYCLEE								
GAS COMB. CYCLEW								
GAS COMB. CYCLES								
PEAK SHORTFALL A								
PEAK SHORTFALL N					2867.0	3634.9	9755.4	20564.1
PEAK SHORTFALL E				3314.0	5552.1	6077.6	8422.9	12289.1
PEAK SHORTFALL W				1703.0	4914.1	9864.7	16607.2	35167.0
PEAK SHORTFALL S				3548.5	4972.5	10672.1	15619.4	22812.6
AVG. SHORTFALL A								
AVG. SHORTFALL N						15495.8	36425.4	68581.6
AVG. SHORTFALL E							8885.5	24323.0
AVG. SHORTFALL W								7661.3
AVG. SHORTFALL S							10462.0	33185.3
TOTAL NEW:			21664.8	74562.1	129727.7	212392.0	327496.4	486635.8
TOTAL CAPACITY:		69070.0	87815.8	137769.1	189729.7	270613.0	384601.4	543740.8

TABLE 6: UTILIZATION OF CAPACITY (IN MW)

TYPE		1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION								
HYDRO	A	213.0	204.5	194.5	185.0	179.5	175.0	175.0
HYDRO	N	3438.6	3304.9	3141.1	2987.1	2898.5	2860.0	2860.0
HYDRO	E	750.5	721.0	685.5	652.0	632.5	625.0	625.0
HYDRO	W	1224.0	1175.8	1118.3	1063.3	1031.8	1012.5	1012.5
HYDRO	S	3730.5	3583.4	3407.9	3240.9	3144.6	3105.0	3105.0
COAL FIRED	A	132.0	115.5	109.5	114.4	111.1	110.0	110.0
COAL FIRED	N	4890.3	5456.2	6646.2	6256.8	4047.6	4000.0	4000.0
COAL FIRED	E	2840.5	3205.9	4111.8	3910.2	2213.4	2205.0	2205.0
COAL FIRED	W	8687.1	8329.0	9504.6	7960.5	7308.5	7000.0	7000.0
COAL FIRED	S	4246.1	4045.0	4616.4	3658.5	3549.5	3500.0	3500.0
GAS FIRED	A	38.6	37.1	35.3	201.0	195.0	192.0	115.3
GAS FIRED	N	711.6	683.4	649.8	618.0	600.0	600.0	600.0
GAS FIRED	E	19.0	18.3	17.4	16.5	16.0	15.0	15.0
GAS FIRED	W	455.4	437.4	415.8	395.4	384.0	384.0	384.0
GAS FIRED	S	39.6	37.8	36.0	34.2	33.6	33.0	33.0
NUCLEAR	N	537.0	516.0	490.8	466.8	452.4	450.0	450.0
NUCLEAR	W	252.0	241.8	230.4	219.0	212.4	210.0	210.0
NUCLEAR	S	282.0	1.5	257.4	244.8	237.6	234.0	234.0
TOTAL EXISTING:		32487.7	32114.6	35668.5	32224.4	27248.1	26710.5	26633.8

NEW GENERATION								
COAL 210 MW	A							
COAL 210 MW	N		476.5	606.2	2460.9	2732.6	2312.2	2732.6
COAL 210 MW	E		43.8	292.2	292.2	2585.1	2187.4	2585.1
COAL 210 MW	W		1844.8	4124.8	8001.3	12459.2	18673.1	29899.4
COAL 210 MW	S		381.2	1406.1	2730.9	3343.9	4001.9	4729.5
COAL 500 MW	A							
COAL 500 MW	N		249.3	317.1	1287.3	1429.3	1429.3	1429.3
COAL 500 MW	E		36.7	244.5	244.5	2163.6	2163.6	2163.6
COAL 500 MW	W		3094.8	6472.8	12555.9	21345.1	34630.2	46919.1
COAL 500 MW	S		953.1	3677.6	7142.4	10335.6	12369.5	12369.5
NUCLEAR	N		325.0	975.0	2275.0	3575.0	5200.0	5850.0
NUCLEAR	W		325.0	975.0	2275.0	3575.0	5200.0	5850.0
NUCLEAR	S		325.0	975.0	2275.0	3575.0	5200.0	5850.0
HYDRO 60 MW	A		90.0	300.0	450.0	600.0	750.0	900.0
HYDRO 60 MW	N		220.0	595.0	970.0	1345.0	1650.0	1650.0
HYDRO 60 MW	E		50.0	150.0	250.0	325.0	325.0	325.0
HYDRO 60 MW	W		45.0	135.0	225.0	292.5	292.5	292.5
HYDRO 60 MW	S		54.0	144.0	202.5	202.5	202.5	202.5
HYDRO 100MW	A		150.0	300.0	450.0	600.0	750.0	900.0
HYDRO 100MW	N		450.0	1250.0	2050.0	2650.0	2650.0	2650.0
HYDRO 100MW	E		100.0	200.0	200.0	200.0	200.0	200.0
HYDRO 100MW	W		90.0	90.0	90.0	90.0	90.0	90.0
HYDRO 100MW	S		112.5	225.0	225.0	225.0	225.0	225.0
GAS TUR 60MW	A			138.8	173.5	313.3	313.3	501.7
GAS TUR 60MW	N			1970.3	2024.3	2054.3	2054.3	2054.3
GAS TUR 60MW	E			20.7	21.6	22.1	23.1	23.1
GAS TUR 60MW	W			1494.3	1494.3	1494.3	1494.3	1494.3
GAS TUR 60MW	S						0.6	0.6
LG HYDRO COST 1A			280.7	1200.0	1800.0	2400.0	3000.0	3300.0
LG HYDRO COST 1N			1200.0	2400.0	2400.0	2400.0	2400.0	2400.0
LG HYDRO COST 1E			240.0	420.0	420.0	420.0	420.0	420.0
LG HYDRO COST 1W			156.0	336.0	336.0	336.0	336.0	336.0
LG HYDRO COST 1S			120.0	240.0	360.0	360.0	360.0	360.0
LG HYDRO COST 2A					900.0	1800.0	2700.0	3300.0
LG HYDRO COST 2N			600.0	1200.0	1800.0	2400.0	2400.0	2400.0
LG HYDRO COST 2E			180.0	240.0	420.0	420.0	420.0	420.0
LG HYDRO COST 2W			120.0	180.0	300.0	300.0	300.0	300.0
LG HYDRO COST 2S			120.0	120.0	240.0	360.0	360.0	360.0
LG HYDRO COST 3A					766.6	1666.6	2566.6	3300.0
LG HYDRO COST 3N			157.4	157.4	757.4	1357.4	2257.4	2400.0
LG HYDRO COST 3E					180.0	360.0	480.0	480.0
LG HYDRO COST 3W					180.0	360.0	360.0	360.0
LG HYDRO COST 3S					120.0	240.0	360.0	480.0
LG HYDRO COST 4A						900.0	2100.0	3300.0
LG HYDRO COST 4N					600.0	1200.0	1800.0	2100.0
LG HYDRO COST 4E					120.0	300.0	480.0	480.0
LG HYDRO COST 4W					60.0	180.0	300.0	300.0
LG HYDRO COST 4S					120.0	240.0	360.0	480.0
GAS COMB. CYCLEA					240.5	481.0	484.0	372.3
GAS COMB. CYCLEN								
GAS COMB. CYCLEE								
GAS COMB. CYCLEW								
GAS COMB. CYCLES								
PEAK SHORTFALL A					716.7	908.7	2430.9	5141.0
PEAK SHORTFALL N				592.8	1388.0	1519.4	2105.7	3072.3
PEAK SHORTFALL E					905.8	2466.2	4151.8	8791.8
PEAK SHORTFALL W						2668.0	3904.9	5703.2
PEAK SHORTFALL S								
AVG. SHORTFALL A						9297.5	21855.2	41148.9
AVG. SHORTFALL N							5091.3	14593.8
AVG. SHORTFALL E								4596.8
AVG. SHORTFALL W							6277.2	19911.2
AVG. SHORTFALL S								
TOTAL NEW:			12590.9	34165.4	65497.5	112874.1	174456.8	262494.2
TOTAL CAPACITY:		32487.7	44705.5	69834.0	97722.0	140122.2	201167.3	289128.0

TABLE 7: ENERGY RESOURCE CONSUMPTION

7.1 CONSUMPTION OF HYDROPOTENTIAL
IN MW

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	213	724	1992	4545	8135	12025	15154
NORTH	3434	5924	8732	11549	14232	15996	16438
EAST	749	1289	1693	2239	2654	2946	2946
WEST	1222	1585	1857	2251	2587	2687	2687
SOUTH	3725	3984	4131	4502	4766	4966	5205
SUM:	9344	13507	18405	25087	32373	38620	42431

7.2 CONSUMPTION OF COAL DOM A1
IN 000 TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	694	607	576	601	584	578	578
NORTH	29987	37376	45739	58601	47288	44676	46996
EAST	17418	20090	28090	26853	39021	36775	38970
WEST	54030	77980	115333	158563	224536	325573	451042
SOUTH	27153	32897	56288	75381	94571	108398	112413
SUM:	129282	168949	246024	320000	406000	516000	650000

7.3 CONSUMPTION OF NATURAL GAS
IN 000 000m3

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	101	97	458	1616	2600	2600	2600
NORTH	1870	1796	6886	6944	6975	6975	6975
EAST	50	48	100	100	100	100	100
WEST	1197	1149	5020	4966	4936	4936	4936
SOUTH	104	99	95	90	88	88	88
SUM:	3322	3190	12558	13716	14700	14700	14700

7.4 CONSUMPTION OF FUEL OIL
IN m^3

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	5782	3059	4796	5011	4866	4818	4818
NORTH	214193	270772	331542	438218	359577	339079	357492
EAST	124415	143943	203603	194773	304939	287151	304571
WEST	380493	581168	880474	1249077	1800742	2641284	3671248
SOUTH	185977	235615	424863	592692	754628	870367	902236
SUM:	910860	1236557	1845279	2479770	3224751	4142699	5240366

7.5 CONSUMPTION OF NUCLEAR FUEL
IN 000 kg U

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.							
NORTH	429	673	1172	2193	3221	4519	5039
EAST							
WEST	202	453	964	1995	3029	4327	4847
SOUTH	226	261	986	2015	3049	4346	4866
SUM:	857	1387	3122	6203	9299	13192	14751

TABLE 8: ENVIRONMENTAL EMISSIONS

8.1 EMISSIONS OF PARTICULATES
IN TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	22201	19426	18417	19241	18686	18501	18501
NORTH	959585	1091489	1330662	1335390	913776	889705	904435
EAST	557380	631223	821141	781582	560915	545331	559267
WEST	1727438	1772392	2142274	2072315	2245149	2622655	3220560
SOUTH	870374	858382	1056768	964503	1016785	1063548	1089044
SUM:	4136978	4372912	5369262	5173031	4755311	5139740	5791807

8.2 EMISSIONS OF CARBON DIOXIDE
IN 000 TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	1371	1217	1884	4245	6183	6173	6173
NORTH	54290	66613	90894	112755	93757	89350	93265
EAST	29462	33964	47565	45481	66105	62314	66018
WEST	93712	134143	205063	278110	389701	560699	772887
SOUTH	45959	55682	95239	127596	160099	183510	190286
SUM:	224793	291619	440645	568188	715844	902046	1128628

8.3 EMISSIONS OF SULPHUR DIOXIDE
IN TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	6692	5865	9208	17120	26935	26951	28765
NORTH	288889	359307	490981	614540	506867	481977	504073
EAST	166766	192310	269269	257458	372540	351167	372071
WEST	511057	738780	1132534	1544021	2171193	3131401	4324298
SOUTH	256753	311388	533440	715137	897410	1028794	1067037
SUM:	1230158	1607650	2435432	3148276	3974945	5020290	6296244

8.4 EMISSIONS OF NITROGEN OXIDES
IN TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.	7089	6276	8993	18880	26922	26870	26870
NORTH	285467	351451	469159	585810	484312	460694	481685
EAST	157179	181217	253696	242570	352517	332194	352053
WEST	497004	712339	1081174	1470151	2064003	2973779	4104878
SOUTH	246357	297980	508642	680234	852780	977205	1013536
SUM:	1193097	1549264	2321664	2997645	3780534	4770743	5979023

8.5 GENERATION OF NUCLEAR WASTE
IN 000 M3

REGION	1991	1996	2001	2006	2011	2016	2021
N.E.							
NORTH	4986	7809	13611	25459	37397	52464	58499
EAST							
WEST	2340	5263	11193	23158	35168	50235	56271
SOUTH	2619	3032	11444	23398	35402	50458	56494
SUM:	9945	16104	36247	72015	107967	153157	171264

TABLE 9A: NORTH-EAST INDIA
SUPPLY / DEMAND BALANCES

9A.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	426.0	409.0	389.0	370.0	359.0	350.0	350.0
COAL FIRED	240.0	231.0	219.0	208.0	202.0	200.0	200.0
GAS FIRED	386.0	371.0	353.0	335.0	325.0	320.0	320.0
TOTAL EXISTING:	1052.0	1011.0	961.0	913.0	886.0	870.0	870.0
NEW GENERATION							
COAL 210 MW							
COAL 500 MW							
HYDRO 60 MW		300.0	600.0	900.0	1200.0	1500.0	1800.0
HYDRO 100MW		300.0	600.0	900.0	1200.0	1500.0	1800.0
GAS TUR 60MW			694.0	694.0	1253.4	1253.4	2006.9
LG HYDRO COST 1		1000.0	2000.0	3000.0	4000.0	5000.0	5500.0
LG HYDRO COST 2				1500.0	3000.0	4500.0	5500.0
LG HYDRO COST 3				1277.6	2777.6	4277.6	5500.0
LG HYDRO COST 4					1500.0	3500.0	5500.0
GAS COMB. CYCLE				370.0	740.0	744.6	744.6
PEAK SHORTFALL							
AVG. SHORTFALL							
TOTAL NEW:		1600.0	3894.0	8641.6	15671.0	22275.6	28351.5
TOTAL CAPACITY:	1052.0	2611.0	4855.0	9554.6	16557.0	23145.6	29221.5

9A.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	298.2	286.3	272.3	259.0	251.3	245.0	245.0
COAL FIRED	180.0	173.3	164.3	156.0	151.5	150.0	150.0
GAS FIRED	328.1	315.4	300.1	284.8	276.3	272.0	272.0
NEW PEAK CAPACITY							
HYDRO 60 MW		270.0	540.0	810.0	1080.0	1350.0	1620.0
HYDRO 100MW		270.0	540.0	810.0	1080.0	1350.0	1620.0
GAS TUR 60MW			451.1	451.1	814.7	814.7	1304.5
LG HYDRO COST 1		900.0	1800.0	2700.0	3600.0	4500.0	4950.0
LG HYDRO COST 2				1350.0	2700.0	4050.0	4950.0
LG HYDRO COST 3				1149.9	2499.9	3849.9	4950.0
LG HYDRO COST 4					1350.0	3150.0	4950.0
GAS COMB. CYCLE				314.5	629.0	632.9	632.9
PEAK GENERATION:	806.3	2214.9	4067.7	8285.2	14432.6	20364.5	25644.4
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM E							
-EXPORT TO E	30.9	225.0	711.3	2774.2	5006.4	5969.5	4200.1
MAX PEAK SUPPLY:	775.4	1989.9	3356.4	5511.0	9426.2	14395.0	21444.3
-SURPLUS PEAK	74.9	548.7		420.1	1179.9	1087.4	
-DISTRIBUTION	700.5	1441.2	3356.4	5091.0	8246.3	13307.5	21444.3
-DIST LOSSES	134.5	276.7	644.4	977.5	1583.3	2555.0	4117.3
+DSM GENER.							
+DECENT. GENER.		82.5	201.0	301.5	402.0	502.5	603.0
-PEAK DEMAND	566.0	1247.0	2913.0	4415.0	7065.0	11255.0	17930.0

9A.3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS		150.0	300.0	450.0	600.0	750.0	900.0
SOLAR THERMAL							
MICRO HYDEL			120.0	180.0	240.0	300.0	360.0
PHOTOVOLTAIC							
WIND POWER							
TOTAL:		150.0	420.0	630.0	840.0	1050 0	1260.0

9A.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	213.0	204.5	194.5	185.0	179.5	175.0	175.0
+COAL FIRED	132.0	115.5	109.5	114.4	111.1	110.0	110.0
+GAS FIRED	38.6	37.1	35.3	201.0	195.0	192.0	115.3
NEW SITES							
+HYDRO 60 MW		90.0	300.0	450.0	600.0	750.0	900.0
+HYDRO 100MW		150.0	300.0	450.0	600.0	750.0	900.0
+GAS TUR 60MW			138.8	173.5	313.3	313.3	501.7
+LG HYDRO COST 1		280.7	1200.0	1800.0	2400.0	3000.0	3300.0
+LG HYDRO COST 2				900.0	1800.0	2700.0	3300.0
+LG HYDRO COST 3				766.6	1666.6	2566.6	3300.0
+LG HYDRO COST 4					900.0	2100.0	3300.0
+GAS COMB. CYCLE				240.5	481.0	484.0	372.3
-TOTAL:	383.6	877.8	2278.1	5281.0	9246.5	13140.9	16274.3
-EXPORT TO E	30.9	225.0	711.3	2774.2	5006.4	5969.5	4200.1
-MAX AVG. SUPPLY:	352.7	652.8	1566.8	2506.8	4240.1	7171.4	12074.3
-SURPLUS AVG.							
-DISTRIBUTION:	352.7	652.8	1566.8	2506.8	4240.1	7171.4	12074.3
-DIST LOSSES	67.7	125.3	300.8	481.3	814.1	1376.9	2318.3
+DSM GENER.							
+DECENT. GENER.		82.5	201.0	301.5	402.0	502.5	603.0
-AVG. DEMAND	285.0	610.0	1467.0	2327.0	3828.0	6297.0	10359.0

TABLE 9N: NORTHERN INDIA
SUPPLY / DEMAND BALANCES

9N.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	6252.0	6009.0	5711.0	5431.0	5270.0	5200.0	5200.0
COAL FIRED	12004.0	11531.0	11077.0	10428.0	10119.0	10000.0	10000.0
GAS FIRED	1186.0	1139.0	1083.0	1030.0	1000.0	1000.0	1000.0
NUCLEAR	895.0	860.0	818.0	778.0	754.0	750.0	750.0
TOTAL EXISTING:	20337.0	19539.0	18689.0	17667.0	17143.0	16950.0	16950.0
NEW GENERATION							
COAL 210 MW		733.1	932.6	3786.0	4204.0	4204.0	4204.0
COAL 500 MW		366.6	466.3	1893.0	2102.0	2102.0	2102.0
NUCLEAR		500.0	1500.0	3500.0	5500.0	8000.0	9000.0
HYDRO 60 MW		440.0	1190.0	1940.0	2690.0	3300.0	3300.0
HYDRO 100MW		900.0	2500.0	4100.0	5300.0	5300.0	5300.0
GAS TUR 60MW			9851.4	10121.4	10271.4	10271.4	10271.4
LG HYDRO COST 1		2000.0	4000.0	4000.0	4000.0	4000.0	4000.0
LG HYDRO COST 2		1000.0	2000.0	3000.0	4000.0	4000.0	4000.0
LG HYDRO COST 3		262.4	262.4	1262.4	2262.4	3762.4	4000.0
LG HYDRO COST 4				1000.0	2000.0	3000.0	3500.0
GAS COMB. CYCLE							
PEAK SHORTFALL				2867.0	3634.9	9755.4	20564.1
AVG. SHORTFALL					15495.8	36425.4	68581.6
TOTAL NEW:		6202.1	22702.7	37469.8	61460.4	94120.6	138823.0
TOTAL CAPACITY:	20337.0	25741.1	41391.7	55136.8	78603.4	111070.6	155773.0

9N.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	5314.2	5107.7	4854.4	4616.4	4479.5	4420.0	4420.0
COAL FIRED	10803.6	10377.9	9969.3	9385.2	9107.1	9000.0	9000.0
GAS FIRED	1008.1	968.2	920.6	875.5	850.0	850.0	850.0
NUCLEAR	671.3	645.0	613.5	583.5	565.5	562.5	562.5
NEW PEAK CAPACITY							
COAL 210 MW		513.2	652.8	2650.2	2942.8	2942.8	2942.8
COAL 500 MW		274.9	349.7	1419.8	1576.5	1576.5	1576.5
NUCLEAR		375.0	1125.0	2625.0	4125.0	6000.0	6750.0
HYDRO 60 MW		396.0	1071.0	1746.0	2421.0	2970.0	2970.0
HYDRO 100MW		810.0	2250.0	3690.0	4770.0	4770.0	4770.0
GAS TUR 60MW			6403.4	6578.9	6676.4	6676.4	6676.4
LG HYDRO COST 1		1800.0	3600.0	3600.0	3600.0	3600.0	3600.0
LG HYDRO COST 2		900.0	1800.0	2700.0	3600.0	3600.0	3600.0
LG HYDRO COST 3		236.1	236.1	1136.1	2036.1	3386.1	3600.0
LG HYDRO COST 4				900.0	1800.0	2700.0	3150.0
PEAK SHORTFALL				2867.0	3634.9	9755.4	20564.1
AVG. SHORTFALL					11621.8	27319.0	51436.2
PEAK GENERATION:	17797.2	22403.9	33845.8	45373.6	63806.6	90128.8	126468.4
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM E	129.6						
+IMPORT FROM W	423.0		432.0	432.0	432.0		
-EXPORT TO E		133.0					
-EXPORT TO W							
MAX PEAK SUPPLY:	18349.7	22268.9	34277.8	45805.6	64238.6	90128.8	126468.4
-SURPLUS PEAK							

	1991	1996	2001	2006	2011	2016	2021
-DISTRIBUTION	18349.7	22268.9	34277.8	45805.6	64238.6	90128.8	126468.4
-DIST LOSSES	3816.7	4631.9	7129.0	9527.6	13361.6	18746.8	26305.4
+DSM GENER.							
+DECENT. GENER.		55.0	182.0	273.0	364.0	455.0	546.0
-PEAK DEMAND	14533.0	17692.0	27330.0	36551.0	51241.0	71837.0	100709.0

9N.3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS		100.0	200.0	300.0	400.0	500.0	600.0
SOLAR THERMAL							
MICRO HYDEL			240.0	360.0	480.0	600.0	720.0
PHOTOVOLTAIC							
WIND POWER							
TOTAL:		100.0	440.0	660.0	880.0	1100.0	1320.0

9N.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	3438.6	3304.9	3141.1	2987.1	2898.5	2860.0	2860.0
+COAL FIRED	4890.3	5456.2	6646.2	6256.8	4047.6	4000.0	4000.0
+GAS FIRED	711.6	683.4	649.8	618.0	600.0	600.0	600.0
+NUCLEAR	537.0	516.0	490.8	466.8	452.4	450.0	450.0
NEW SITES							
+COAL 210 MW		476.5	606.2	2460.9	2732.6	2312.2	2732.6
+COAL 500 MW		249.3	317.1	1287.3	1429.3	1429.3	1429.3
+NUCLEAR		325.0	975.0	2275.0	3575.0	5200.0	5850.0
+HYDRO 60 MW		220.0	595.0	970.0	1345.0	1650.0	1650.0
+HYDRO 100MW		450.0	1250.0	2050.0	2650.0	2650.0	2650.0
+GAS TUR 60MW			1970.3	2024.3	2054.3	2054.3	2054.3
+LG HYDRO COST 1		1200.0	2400.0	2400.0	2400.0	2400.0	2400.0
+LG HYDRO COST 2		600.0	1200.0	1800.0	2400.0	2400.0	2400.0
+LG HYDRO COST 3		157.4	157.4	757.4	1357.4	2257.4	2400.0
+LG HYDRO COST 4				600.0	1200.0	1800.0	2100.0
+PEAK SHORTFALL				716.7	908.7	2438.9	5141.0
+AVG. SHORTFALL					9297.5	21855.2	41148.9
-TOTAL:	9577.5	13638.8	20398.8	27670.3	39348.3	56357.3	79866.2
+IMPORT FROM E	129.6						
+IMPORT FROM W	423.0		432.0	432.0	432.0		
-EXPORT TO E		135.0					
-MAX AVG. SUPPLY:	10130.1	13503.8	20830.8	28102.3	39780.3	56357.3	79866.2
-SURPLUS AVG.							
-DISTRIBUTION:	10130.1	13503.8	20830.8	28102.3	39780.3	56357.3	79866.2

	1991	1996	2001	2006	2011	2016	2021
-DIST LOSSES	2107.1	2808.8	4332.8	5845.3	8274.3	11722.3	16612.
+DSM GENER.							
+DECENT. GENER.		55.0	182.0	273.0	364.0	455.0	546.
-AVG. DEMAND	8023.0	10750.0	16680.0	22530.0	31870.0	45090.0	63800

TABLE 9E: EASTERN INDIA
SUPPLY / DEMAND BALANCES

9E.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	1501.0	1442.0	1371.0	1304.0	1265.0	1250.0	1250.0
COAL FIRED	7502.0	7206.0	6853.0	6517.0	6324.0	6300.0	6300.0
GAS FIRED	190.0	183.0	174.0	165.0	160.0	150.0	150.0
TOTAL EXISTING:	9193.0	8831.0	8398.0	7986.0	7749.0	7700.0	7700.0
NEW GENERATION							
COAL 210 MW		67.4	449.5	449.5	3977.1	3977.1	3977.1
COAL 500 MW		53.9	359.6	359.6	3181.7	3181.7	3181.7
HYDRO 60 MW		100.0	300.0	500.0	650.0	650.0	650.0
HYDRO 100MW		200.0	400.0	400.0	400.0	400.0	400.0
GAS TUR 60MW			103.3	107.8	110.3	115.3	115.3
LG HYDRO COST 1		400.0	700.0	700.0	700.0	700.0	700.0
LG HYDRO COST 2		300.0	400.0	700.0	700.0	700.0	700.0
LG HYDRO COST 3				300.0	600.0	800.0	800.0
LG HYDRO COST 4				200.0	500.0	800.0	800.0
GAS COMB. CYCLE							
PEAK SHORTFALL			3314.0	5552.1	6077.6	8422.9	12289.1
AVG. SHORTFALL						8485.5	24323.0
TOTAL NEW:		1121.3	6026.3	9268.9	16896.6	28232.5	47936.1
TOTAL CAPACITY:	9193.0	9952.3	14424.3	17254.9	24645.6	35932.5	55636.1

9E.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	1275.9	1225.7	1165.4	1108.4	1075.3	1062.5	1062.5
COAL FIRED	5626.5	5404.5	5139.8	4887.8	4743.0	4725.0	4725.0
GAS FIRED	161.5	155.6	147.9	140.3	136.0	127.5	127.5
NEW PEAK CAPACITY							
COAL 210 MW		47.2	314.6	314.6	2784.0	2784.0	2784.0
COAL 500 MW		40.4	269.7	269.7	2386.3	2386.3	2386.3
HYDRO 60 MW		90.0	270.0	450.0	585.0	585.0	585.0
HYDRO 100MW		180.0	360.0	360.0	360.0	360.0	360.0
GAS TUR 60MW			67.1	70.0	71.7	74.9	74.9
LG HYDRO COST 1		360.0	630.0	630.0	630.0	630.0	630.0
LG HYDRO COST 2		270.0	360.0	630.0	630.0	630.0	630.0
LG HYDRO COST 3				270.0	540.0	720.0	720.0
LG HYDRO COST 4				180.0	450.0	720.0	720.0
PEAK SHORTFALL			3314.0	5552.1	6077.6	8422.9	12289.1
AVG. SHORTFALL						6364.1	18242.2
PEAK GENERATION:	7063.9	7773.3	12038.5	14862.8	20468.7	29592.2	45336.5
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM N		129.6					
+IMPORT FROM S			449.3	449.3			
+IMPORT FROM A	29.6	216.0	682.8	2663.2	4806.2	5730.7	4032.1
+IMPORT FROM W		216.0	216.0	113.5			
-EXPORT TO N	135.0						
-EXPORT TO S	108.0						
-EXPORT TO A							
-EXPORT TO W	225.0						
MAX PEAK SUPPLY:	6625.5	8334.9	13386.6	18088.8	25274.9	35322.9	49368.5
-SURPLUS PEAK	1282.2						

-DISTRIBUTION	5343.3	8334.9	13386.6	18088.8	25274.9	35322.9	49368.5
-DIST LOSSES	892.3	1391.9	2235.6	3020.8	4220.9	5898.9	8244.5
+DSM GENER.							
+DECENT. GENER.			36.0	54.0	72.0	90.0	108.0
-PEAK DEMAND	4451.0	6943.0	11187.0	15122.0	21126.0	29514.0	41232.0

9E.3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS							
SOLAR THERMAL							
MICRO HYDEL			120.0	180.0	240.0	300.0	360.0
PHOTOVOLTAIC							
WIND POWER							
TOTAL:			120.0	180.0	240.0	300.0	360.0

9E.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	750.5	721.0	685.5	652.0	632.5	625.0	625.0
+COAL FIRED	2840.5	3205.9	4111.8	3910.2	2213.4	2205.0	2205.0
+GAS FIRED	19.0	18.3	17.4	16.5	16.0	15.0	15.0
NEW SITES							
+COAL 210 MW		43.8	292.2	292.2	2585.1	2187.4	2585.1
+COAL 500 MW		36.7	244.5	244.5	2163.6	2163.6	2163.6
+HYDRO 60 MW		50.0	150.0	250.0	325.0	325.0	325.0
+HYDRO 100MW		100.0	200.0	200.0	200.0	200.0	200.0
+GAS TUR 60MW			20.7	21.6	22.1	23.1	23.1
+LG HYDRO COST 1		240.0	420.0	420.0	420.0	420.0	420.0
+LG HYDRO COST 2		180.0	240.0	420.0	420.0	420.0	420.0
+LG HYDRO COST 3				180.0	360.0	480.0	480.0
+LG HYDRO COST 4				120.0	300.0	480.0	480.0
+PEAK SHORTFALL			592.8	1388.0	1519.4	2105.7	3072.3
+AVG. SHORTFALL						5091.3	14593.8
-TOTAL:	3610.0	4595.7	6974.8	8114.9	11177.0	16741.1	27607.8
+IMPORT FROM N		129.6					
+IMPORT FROM S			449.3	449.3			
+IMPORT FROM A	29.6	216.0	682.8	2663.2	4806.2	5730.7	4032.1
+IMPORT FROM W		216.0	216.0	113.5			
-EXPORT TO N	135.0						
-EXPORT TO S	108.0						
-EXPORT TO W	225.0						
-MAX AVG. SUPPLY:	3171.7	5157.3	8322.9	11340.9	15983.2	22471.8	31639.9
-SURPLUS AVG.							

-DISTRIBUTION:	3171.7	5157.3	8322.9	11340.9	15983.2	22471.8	31639.9
-DIST LOSSES	529.7	861.3	1389.9	1893.9	2669.2	3752.8	5283.9
+DSM GENER.							
+DECENT. GENER.			36.0	54.0	72.0	90.0	108.0
-AVG. DEMAND	2642.0	4296.0	6969.0	9501.0	13386.0	18809.0	26464.0

TABLE 9W: WESTERN INDIA
SUPPLY / DEMAND BALANCES

9W.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	2720.0	2613.0	2485.0	2363.0	2293.0	2250.0	2250.0
COAL FIRED	17341.0	16658.0	15841.0	15065.0	14617.0	14000.0	14000.0
GAS FIRED	759.0	729.0	693.0	659.0	640.0	640.0	640.0
NUCLEAR	420.0	403.0	384.0	365.0	354.0	350.0	350.0
TOTAL EXISTING:	21240.0	20403.0	19403.0	18452.0	17904.0	17240.0	17240.0
NEW GENERATION							
COAL 210 MW		3034.1	6345.8	12309.7	20926.6	33951.1	45999.1
COAL 500 MW		4551.2	9518.8	18464.6	31389.8	50926.7	68998.6
NUCLEAR		500.0	1500.0	3500.0	5500.0	8000.0	9000.0
HYDRO 60 MW		100.0	300.0	500.0	650.0	650.0	650.0
HYDRO 100MW		200.0	200.0	200.0	200.0	200.0	200.0
GAS TUR 60MW			7471.6	7471.6	7471.6	7471.6	7471.6
LG HYDRO COST 1		260.0	560.0	560.0	560.0	560.0	560.0
LG HYDRO COST 2		200.0	300.0	500.0	500.0	500.0	500.0
LG HYDRO COST 3				300.0	600.0	600.0	600.0
LG HYDRO COST 4				100.0	300.0	500.0	500.0
GAS COMB. CYCLE							
PEAK SHORTFALL			1703.0	4914.1	9864.7	16607.2	35167.0
AVG. SHORTFALL							7661.3
TOTAL NEW:		8845.4	27899.2	48820.0	77962.7	119966.7	177307.7
TOTAL CAPACITY:	21240.0	29248.4	47302.2	67272.0	95866.7	137206.7	194547.7

9W.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

• TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	2312.0	2221.1	2112.3	2008.6	1949.1	1912.5	1912.5
COAL FIRED	13005.8	12493.5	11880.8	11298.8	10962.8	10500.0	10500.0
GAS FIRED	645.2	619.7	589.1	560.2	544.0	544.0	544.0
NUCLEAR	315.0	302.3	288.0	273.8	265.5	262.5	262.5
NEW PEAK CAPACITY							
COAL 210 MW		2123.9	4442.1	8616.8	14648.6	23765.8	32199.4
COAL 500 MW		3413.4	7139.1	13848.4	23542.4	38195.0	51749.0
NUCLEAR		375.0	1125.0	2625.0	4125.0	6000.0	6750.0
HYDRO 60 MW		90.0	270.0	450.0	585.0	585.0	585.0
HYDRO 100MW		180.0	180.0	180.0	180.0	180.0	180.0
GAS TUR 60MW			4856.6	4856.6	4856.6	4856.6	4856.6
LG HYDRO COST 1		234.0	504.0	504.0	504.0	504.0	504.0
LG HYDRO COST 2		180.0	270.0	450.0	450.0	450.0	450.0
LG HYDRO COST 3				270.0	540.0	540.0	540.0
LG HYDRO COST 4				90.0	270.0	450.0	450.0
PEAK SHORTFALL			1703.0	4914.1	9864.7	16607.2	35167.0
AVG. SHORTFALL							5746.0
PEAK GENERATION:	16277.9	22232.8	35359.7	50946.1	73287.5	105352.6	152395.9
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM N							
+IMPORT FROM S	294.5						
+IMPORT FROM E	216.0						
-EXPORT TO N	440.6		450.0	450.0	450.0		
-EXPORT TO S		450.0					
-EXPORT TO E		225.0	225.0	118.2			
MAX PEAK SUPPLY:	16347.8	21557.8	34684.7	50377.9	72837.5	105352.6	152395.9

-SURPLUS PEAK							
-DISTRIBUTION	16347.8	21557.8	34684.7	50377.9	72837.5	105352.6	152395.9
-DIST LOSSES	2762.8	3643.3	5861.7	8513.9	12309.5	17804.6	25754.9
+DSM GENER.							
+DECENT. GENER.		82.5	240.0	360.0	480.0	600.0	720.0
-PEAK DEMAND	13585.0	17997.0	29063.0	42224.0	61008.0	88148.0	127361.0

9W.3 DSM AND DECENTRALIZED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS		150.0	300.0	450.0	600.0	750.0	900.0
SOLAR THERMAL							
MICRO HYDEL							
PHOTOVOLTAIC							
WIND POWER			300.0	450.0	600.0	750.0	900.0
TOTAL:		150.0	600.0	900.0	1200.0	1500.0	1800.0

9W.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	1224.0	1175.8	1118.3	1063.3	1031.8	1012.5	1012.5
+COAL FIRED	8687.1	8329.0	9504.6	7960.5	7308.5	7000.0	7000.0
+GAS FIRED	455.4	437.4	415.8	395.4	384.0	384.0	384.0
+NUCLEAR	252.0	241.8	230.4	219.0	212.4	210.0	210.0
NEW SITES							
+COAL 210 MW		1844.8	4124.8	8001.3	12459.2	18673.1	29899.4
+COAL 500 MW		3094.8	6472 8	12555.9	21345.1	34630.2	46919.1
+NUCLEAR		325.0	975.0	2275.0	3575.0	5200.0	5850.0
+HYDRO 60 MW		45.0	135.0	225.0	292.5	292.5	292.5
+HYDRO 100MW		90.0	90.0	90.0	90.0	90.0	90.0
+GAS TUR 60MW			1494.3	1494.3	1494.3	1494.3	1494.3
+LG HYDRO COST 1		156.0	336.0	336.0	336.0	336.0	336.0
+LG HYDRO COST 2		120.0	180.0	300.0	300.0	300.0	300.0
+LG HYDRO COST 3				180.0	360.0	360.0	360.0
+LG HYDRO COST 4				60.0	180.0	300.0	300.0
+PEAK SHORTFALL				905.8	2466.2	4151.8	8791.8
+AVG. SHORTFALL							4596.8
-TOTAL:	10618.5	15859.7	25076.9	36061.6	51835.1	74434.4	107836.3
+IMPORT FROM S	294.5						
+IMPORT FROM E	216.0						
-EXPORT TO N	440.6		450.0	450.0	450.0		
-EXPORT TO S		450.0					
-EXPORT TO E		225.0	225.0	118.2			
-MAX AVG. SUPPLY:	10688.3	15184.7	24401.9	35493.4	51385.1	74434.4	107836.3
-SURPLUS AVG.							

-DISTRIBUTION:	10680.3	15184.7	24481.9	35493.4	51385.1	74434.4	107836.3
-DIST LOSSES	1806.3	2566.2	4123.9	5998.4	8684.1	12579.4	18224.3
+DSM GENER.							
+DECENT. GENER.		82.5	240.0	360.0	480.0	600.0	720.0
-AVG. DEMAND	8882.0	12701.0	20518.0	29855.0	43181.0	62455.0	90332.0

TABLE 98: SOUTHERN INDIA
SUPPLY / DEMAND BALANCES

98.1 INSTALLED REGIONAL CAPACITY (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING GENERATION							
HYDRO	8290.0	7963.0	7573.0	7202.0	6988.0	6900.0	6900.0
COAL FIRED	8422.0	8090.0	7694.0	7317.0	7099.0	7000.0	7000.0
GAS FIRED	66.0	63.0	60.0	57.0	56.0	55.0	55.0
NUCLEAR	470.0	451.0	429.0	408.0	396.0	390.0	390.0
TOTAL EXISTING:	17248.0	16567.0	15756.0	14984.0	14539.0	14345.0	14345.0
NEW GENERATION							
COAL 210 MW		693.2	2163.3	4201.4	6079.8	7276.2	7276.2
COAL 500 MW		1732.9	5408.2	10503.3	15199.4	18190.4	18190.4
NUCLEAR		500.0	1500.0	3500.0	5500.0	8000.0	9000.0
HYDRO 60 MW		120.0	320.0	450.0	450.0	450.0	450.0
HYDRO 100MW		250.0	500.0	500.0	500.0	500.0	500.0
GAS TUR 60MW						3.0	3.0
LG HYDRO COST 1		200.0	400.0	600.0	600.0	600.0	600.0
LG HYDRO COST 2		200.0	200.0	400.0	600.0	600.0	600.0
LG HYDRO COST 3				200.0	400.0	600.0	800.0
LG HYDRO COST 4				200.0	400.0	600.0	800.0
GAS COMB. CYCLE							
PEAK SHORTFALL			3540.5	4972.5	10672.1	13619.4	22812.6
AVG. SHORTFALL						10462.8	33185.3
TOTAL NEW:		3696.1	14040.0	25527.4	40401.2	62901.0	94217.5
TOTAL CAPACITY:	17248.0	20263.1	29796.0	40511.4	54940.2	77246.0	108562.5

98.2 SUPPLY / DEMAND BALANCE - PEAK POWER (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
EXISTING PEAK CAPACITY							
HYDRO	6632.8	6370.4	6058.4	5761.6	5590.4	5520.0	5520.0
COAL FIRED	5895.4	5663.0	5385.8	5121.9	4969.3	4900.0	4900.0
GAS FIRED	56.1	53.6	51.0	48.5	47.6	46.8	46.8
NUCLEAR	352.5	338.3	321.8	306.0	297.0	292.5	292.5
NEW PEAK CAPACITY							
COAL 210 MW		485.2	1514.3	2941.0	4255.8	5093.3	5093.3
COAL 500 MW		1299.7	4056.1	7877.6	11399.5	13642.8	13642.8
NUCLEAR		375.0	1125.0	2625.0	4125.0	6000.0	6750.0
HYDRO 60 MW		108.0	288.0	405.0	405.0	405.0	405.0
HYDRO 100MW		225.0	450.0	450.0	450.0	450.0	450.0
GAS TUR 60MW						1.9	1.9
LG HYDRO COST 1		180.0	360.0	540.0	540.0	540.0	540.0
LG HYDRO COST 2		180.0	180.0	360.0	540.0	540.0	540.0
LG HYDRO COST 3				180.0	360.0	540.0	720.0
LG HYDRO COST 4				180.0	360.0	540.0	720.0
PEAK SHORTFALL			3540.5	4972.5	10672.1	13619.4	22812.6
AVG. SHORTFALL						7846.5	24809.0
PEAK GENERATION:	12936.0	15278.1	23338.9	31769.1	44011.7	61978.3	87323.9
PEAK IMPORT AND EXPORT CAPACITY							
+IMPORT FROM E	103.7						
+IMPORT FROM W		432.0					
-EXPORT TO E			460.0	460.0			
-EXPORT TO W	306.8						
MAX PEAK SUPPLY:	12732.9	15710.1	22878.9	31301.1	44011.7	61978.3	87323.9
-SURPLUS PEAK	365.5						

-DISTRIBUTION	12367.4	15710.1	22870.9	31301.1	44811.7	61978.3	87323.9
-DIST LOSSES	1830.4	2325.1	3384.9	4632.6	6513.7	9172.8	12923.9
+DSM GENER.							
+DECENT. GENER.		55.0	581.8	751.5	1002.0	1252.5	1503.0
-PEAK DEMAND	10537.0	13440.0	19987.0	27420.0	38500.0	54058.0	75903.0

95.3 DSM AND DECENTRALISED GENERATION (IN MW)

TYPE	1991	1996	2001	2006	2011	2016	2021
DSM OPTIONS							
A1 PUMP RETRO							
A2 EFF PUMP							
D1 REP GLS							
D2 REP FTL							
D3 EFF FRIDGE							
D4 EFF FANS							
D5 EFF A/C							
C1 REP GLS							
C2 REP FTL							
C3 REP HPMV							
C4 IMP HVAC							
I1 REW MOTORS							
I2 OPT PUMPS							
I3 LIGHTING							
I4 ARC FURN							
I5 EFF MOTORS							
TOTAL:							
DECENTRALIZED GENERATION							
BIO-GAS	100.0	200.0	300.0	400.0	500.0	600.0	
SOLAR THERMAL							
MICRO HYDEL		720.0	1080.0	1440.0	1800.0	2160.0	
PHOTOVOLTAIC							
WIND POWER		700.0	1050.0	1400.0	1750.0	2100.0	
TOTAL:	100.0	1620.0	2430.0	3240.0	4050.0	4860.0	

95.4 AVERAGE POWER GENERATION AND DEMAND (IN MW)

ROW	1991	1996	2001	2006	2011	2016	2021
EXISTING SITES							
+HYDRO	3730.5	3503.4	3407.9	3240.9	3144.6	3105.0	3105.0
+COAL FIRED	4246.1	4045.0	4616.4	3658.5	3549.5	3500.0	3500.0
+GAS FIRED	39.6	37.8	36.0	34.2	33.6	33.0	33.0
+NUCLEAR	282.0	1.5	257.4	244.8	237.6	234.0	234.0
NEW SITES							
+COAL 210 MW		381.2	1806.1	2730.9	3343.9	4001.9	4729.5
+COAL 500 MW		953.1	3677.6	7142.4	10335.6	12369.5	12369.5
+NUCLEAR		325.0	975.0	2275.0	3575.0	5200.0	5850.0
+HYDRO 60 MW		54.0	144.0	202.5	202.5	202.5	202.5
+HYDRO 100MW		112.5	225.0	225.0	225.0	225.0	225.0
+GAS TUR 60MW						0.6	0.6
+LG HYDRO COST 1		120.0	240.0	360.0	360.0	360.0	360.0
+LG HYDRO COST 2		120.0	120.0	240.0	360.0	360.0	360.0
+LG HYDRO COST 3				120.0	240.0	360.0	480.0
+LG HYDRO COST 4				120.0	240.0	360.0	480.0
+PEAK SHORTFALL					2668.0	3904.9	5703.2
+AVG. SHORTFALL						6277.2	19911.2
-TOTAL:	8298.2	9733.5	15105.3	20594.2	28515.3	40493.5	57543.4
+IMPORT FROM E	103.7						
+IMPORT FROM W		432.0					
-EXPORT TO E			468.0	468.0			
-EXPORT TO W	306.8						
-MAX AVG. SUPPLY:	8095.1	10165.5	14637.3	20126.2	28515.3	40493.5	57543.4
-SURPLUS AVG.							

-DISTRIBUTION:	8095.1	10165.5	14637.3	20126.2	28515.3	40493.5	57543.4
-DIST LOSSES	1198.1	1504.5	2166.3	2978.7	4220.3	5993.0	8516.4
+DSM GENER.							
+DECENT. GENER.		55.0	501.0	751.5	1002.0	1252.5	1503.0
-AVG. DEMAND	6897.0	8716.0	12972.0	17899.0	25297.0	35753.0	50530.0

TABLE 10: INTERREGIONAL TRANSMISSION

10.1A TRANSMISSION FROM NORTH TO EAST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	150.0	150.0	150.0	150.0	150.0	150.0	150.0
NEW CAPACITY			400.0	400.0	400.0	400.0	400.0
TOTAL: PEAK CAPACITY	150.0	150.0	550.0	550.0	550.0	550.0	550.0
AVG. CAPACITY	135.0	135.0	495.0	495.0	495.0	495.0	495.0
AVG. UTILIZ.		135.0					

10.1B TRANSMISSION FROM EAST TO NORTH

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	150.0	150.0	150.0	150.0	150.0	150.0	150.0
NEW CAPACITY			400.0	400.0	400.0	400.0	400.0
TOTAL: PEAK CAPACITY	150.0	150.0	550.0	550.0	550.0	550.0	550.0
AVG. CAPACITY	135.0	135.0	495.0	495.0	495.0	495.0	495.0
AVG. UTILIZ.	135.0						

10.2A TRANSMISSION FROM NORTH TO WEST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
NEW CAPACITY							
TOTAL: PEAK CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
AVG. CAPACITY	450.0	450.0	450.0	450.0	450.0	450.0	450.0
AVG. UTILIZ.							

10.2B TRANSMISSION FROM WEST TO NORTH

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
NEW CAPACITY							
TOTAL: PEAK CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
AVG. CAPACITY	450.0	450.0	450.0	450.0	450.0	450.0	450.0
AVG. UTILIZ.	440.6		450.0	450.0	450.0		

10.3A TRANSMISSION FROM SOUTH TO EAST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	120.0	120.0	120.0	120.0	120.0	120.0	120.0
NEW CAPACITY			400.0	400.0	400.0	400.0	400.0
TOTAL: PEAK CAPACITY	120.0	120.0	520.0	520.0	520.0	520.0	520.0

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	1991	1996	2001	2006	2011	2016	2021
AVG. CAPACITY	108.0	108.0	468.0	468.0	468.0	468.0	468.0
AVG. UTILIZ.			468.0	468.0			

10.3B TRANSMISSION FROM EAST TO SOUTH

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	120.0	120.0	120.0	120.0	120.0	120.0	120.0
NEW CAPACITY			400.0	400.0	400.0	400.0	400.0
TOTAL: PEAK CAPACITY	120.0	120.0	520.0	520.0	520.0	520.0	520.0
AVG. CAPACITY	108.0	108.0	468.0	468.0	468.0	468.0	468.0
AVG. UTILIZ.	108.0						

10.4A TRANSMISSION FROM SOUTH TO WEST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
NEW CAPACITY							
TOTAL: PEAK CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
AVG. CAPACITY	450.0	450.0	450.0	450.0	450.0	450.0	450.0
AVG. UTILIZ.	306.8						

10.4B TRANSMISSION FROM WEST TO SOUTH

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
NEW CAPACITY							
TOTAL: PEAK CAPACITY	500.0	500.0	500.0	500.0	500.0	500.0	500.0
AVG. CAPACITY	450.0	450.0	450.0	450.0	450.0	450.0	450.0
AVG. UTILIZ.		450.0					

10.5A TRANSMISSION FROM N.E. TO EAST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
NEW CAPACITY			540.3	2832.4	5312.7	6382.8	6382.8
TOTAL: PEAK CAPACITY	250.0	250.0	790.3	3082.4	5562.7	6632.8	6632.8
AVG. CAPACITY	225.0	225.0	711.3	2774.2	5006.4	5969.5	5969.5
AVG. UTILIZ.	30.9	225.0	711.3	2774.2	5006.4	5969.5	4200.1

10.5B TRANSMISSION FROM EAST TO N.E.

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
NEW CAPACITY			540.3	2832.4	5312.7	6382.8	6382.8
TOTAL: PEAK CAPACITY	250.0	250.0	790.3	3082.4	5562.7	6632.8	6632.8
AVG. CAPACITY	225.0	225.0	711.3	2774.2	5006.4	5969.5	5969.5
AVG. UTILIZ.							

10.6A TRANSMISSION FROM WEST TO EAST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
NEW CAPACITY							
TOTAL: PEAK CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
AVG. CAPACITY	225.0	225.0	225.0	225.0	225.0	225.0	225.0
AVG. UTILIZ.		225.0	225.0	118.2			

10.6B TRANSMISSION FROM EAST TO WEST

	1991	1996	2001	2006	2011	2016	2021
EXIST. CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0

NEW CAPACITY

TOTAL:							
PEAK CAPACITY	250.0	250.0	250.0	250.0	250.0	250.0	250.0
AVG. CAPACITY	225.0	225.0	225.0	225.0	225.0	225.0	225.0
AVG. UTILIZ.	225.0						

TABLE 14: FUEL COSTS

HYDROPOTENTIAL IN RUPEES/MW

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA AVG:							

COAL DOM A1 IN RUPEES/TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	320.0	320.0	320.0	320.0	320.0	320.0	320.0
NORTHERN INDIA	280.0	280.0	280.0	280.0	280.0	280.0	280.0
EASTERN INDIA	320.0	320.0	320.0	320.0	320.0	320.0	320.0
WESTERN INDIA	280.0	280.0	280.0	280.0	280.0	280.0	280.0
SOUTHERN INDIA	360.0	360.0	360.0	360.0	360.0	360.0	360.0
INDIA AVG:	312.0	312.0	312.0	312.0	312.0	312.0	312.0

COAL IMPORT 1 IN RUPEES/TONNES

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA							
NORTHERN INDIA							
EASTERN INDIA							
WESTERN INDIA							
SOUTHERN INDIA							
INDIA AVG:							

NATURAL GAS IN RUPEES/000m3

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	1820.0	1820.0	1820.0	1820.0	1820.0	1820.0	1820.0
NORTHERN INDIA	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0
EASTERN INDIA	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0
WESTERN INDIA	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0
SOUTHERN INDIA	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0	2360.0
INDIA AVG:	2252.0	2252.0	2252.0	2252.0	2252.0	2252.0	2252.0

FUEL OIL IN RUPEES/m^3

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
NORTHERN INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
EASTERN INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
WESTERN INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
SOUTHERN INDIA	450.0	450.0	450.0	450.0	450.0	450.0	450.0
INDIA AVG:	450.0	450.0	450.0	450.0	450.0	450.0	450.0

NUCLEAR FUEL IN RUPEES/kg U

REGION	1991	1996	2001	2006	2011	2016	2021

NORTH-EAST INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
NORTHERN INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
EASTERN INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
WESTERN INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
SOUTHERN INDIA	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0
INDIA AVG:	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0	2000.0

TESTING FUEL IN RUPEES/UNITS

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
NORTHERN INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
EASTERN INDIA	997.0	997.0	997.0	997.0	997.0	997.0	997.0
WESTERN INDIA	998.0	998.0	998.0	998.0	998.0	998.0	998.0
SOUTHERN INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
INDIA AVG:	998.4	998.4	998.4	998.4	998.4	998.4	998.4

BACKSTOP FUEL IN RUPEES/UNITS

REGION	1991	1996	2001	2006	2011	2016	2021
NORTH-EAST INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
NORTHERN INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
EASTERN INDIA	997.0	997.0	997.0	997.0	997.0	997.0	997.0
WESTERN INDIA	998.0	998.0	998.0	998.0	998.0	998.0	998.0
SOUTHERN INDIA	999.0	999.0	999.0	999.0	999.0	999.0	999.0
INDIA AVG:	998.4	998.4	998.4	998.4	998.4	998.4	998.4

Appendix G

CANADA-INDIA INSTITUTIONAL LINKAGE PROGRAM RESEARCH PROJECTS AND PARTNER INSTITUTES

Appendix G

CANADA-INDIA INSTITUTIONAL LINKAGE PROGRAM RESEARCH PROJECTS AND PARTNER INSTITUTES

Funded by the Canadian International Development Agency (CIDA), the Canada-India Institutional Linkage Program aims at fostering linkages between applied research institutes in India and Canada through collaborative research. The program is based on the premise that by joining forces to study economic and management issues, Canadian and Indian applied research organizations can play an important role in the transition towards a more mature relationship between Canada and India. The Conference Board of Canada is the executing agency for the program.

I. **Estimating Levels of Regional Economic Development in India**

Centre for Monitoring Indian Economy (CMIE), Bombay
Atlantic Provinces Economic Council (APEC), Halifax

II **Impact of External Transfers on Regional Economies of Kerala, India and the Atlantic Provinces of Canada**

Centre for Development Studies (CDST), Trivandrum
Atlantic Provinces Economic Council (APEC), Halifax

III **Planning for the Indian Power Sector: Environmental and Development Considerations**

Tata Energy Research Institute (TERI), New Delhi
Canadian Energy Research Institute (CERI), Calgary

IV. **Managing Change and Innovation in a Global Economy: The Challenge for the 1990s**

Administrative Staff College of India (ASCI), Bombay
The Banff Centre for Management (BMC), Banff

V **Comparative Fiscal Federalism: Canada and India**

National Institute of Public Finance & Policy (NIPFP), New Delhi
Business Centre for Tax Research (BCTR), The Conference Board of Canada, Ottawa

VI **Trade, Innovation and Industrial Performance**

Institute of Economic Growth (IEG), New Delhi
Indian Institute of Management (IIMA), Ahmedabad
Centre for Trade Policy and Law (CTPL), Ottawa
Centre for International Studies (CIS), Toronto

VII. **Impact of Macro Policies on Women in the Period of Liberalization and Adjustment: Comparative Perspectives from Canada and India**

Centre for Women's Development Studies (CWDS), New Delhi
The North-South Institute (NSI), Ottawa

VIII. **Macroeconomic Modelling for Forecasting and Policy Analysis**

National Council of Applied Economic Research (NCAER), New Delhi
Custom Economic Services (CES), The Conference Board of Canada, Ottawa

IX. **Limiting Carbon Dioxide (CO_2) Emissions Through Economic Instruments: Application to India and Canada**

Indira Gandhi Institute of Development Research (IGIDR), Bombay
The North-South Institute (NSI), Ottawa

Appendix H

CANADA-INDIA INSTITUTIONAL LINKAGE PROGRAM PUBLICATION LIST

Appendix H

CANADA-INDIA INSTITUTIONAL LINKAGE PROGRAM PUBLICATION LIST

Bowes, Laurie, ed. *Energy and the Environment: The Challenge for North-South Co-operation.* Papers from the symposium "Energy and the Environment: The Challenge for North-South Co-operation, Canada-India Context, Toronto and Calgary, Canada, November 1993. Ottawa: The Conference Board of Canada, April 1994.

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